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

Form 10-K

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

For the fiscal year ended December 31, 2019

OR

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

Commission file number: 001-35371

Bonanza Creek Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**61-1630631**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
410 17th Street, Suite 1400	
Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 440-6100
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

(Title of Class)	(Trading Symbol)	(Name of Exchange)
Common Stock, par value $0.01 per share	BCEI	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 (§ 232.405 of this chapter) 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 is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 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 the registrant's voting and non-voting common equity held by non-affiliates on June 30, 2019, based upon the closing price of $20.88 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $429.9 million. Excludes approximately 44,463 shares of the registrant's common stock held by executive officers, directors and stockholders that the registrant has concluded, solely for the purpose of the foregoing calculation, were affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of February 24, 2020: 20,648,266

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement, will be filed with the Securities and Exchange Commission within 120 days of December 31, 2019, as incorporated by reference into Part III of this report for the year ended December 31, 2019.

BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2019

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Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"). When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," "plan," "will," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements include statements related to, among other things:

- the Company's business strategies;
- reserves estimates;
- estimated sales volumes;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;
- anticipated costs;
- compliance with debt covenants;
- ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations, including environmental, health, and safety regulations and liabilities thereunder;
- adequacy of gathering systems and continuous improvement of such gathering systems;
- impact from the lack of available gathering systems and processing facilities in certain areas;
- impact of effectiveness of vapor control systems at central tank batteries;
- natural gas, oil, and natural gas liquid prices and factors affecting the volatility of such prices;
- impact of lower commodity prices;
- sufficiency of impairments;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
- our drilling inventory and drilling intentions;
- impact of potentially disruptive technologies;
- our estimated revenue gains and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals;
- our use of multi-well pads to develop the Niobrara and Codell formations;
- intention to continue to optimize enhanced completion techniques and well design changes;
- stated working interest percentages;
- management and technical team;
- outcomes and effects of litigation, claims, and disputes;
- primary sources of future production growth;
- full delineation of the Niobrara B, C, and Codell benches in our legacy, French Lake, and northern acreage;

- our ability to replace oil and natural gas reserves;
- our ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking;
- impact of recently issued accounting pronouncements;
- impact of the loss a single customer or any purchaser of our products;
- timing and ability to meet certain volume commitments related to purchase and transportation agreements;
- the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, and other industry-related constraints;
- our financial position;
- our cash flow and liquidity;
- the adequacy of our insurance; and
- other statements concerning our operations, economic performance, and financial condition.

We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward-looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- further declines or volatility in the prices we receive for our oil, natural gas liquids, and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our access to capital;
- our ability to generate sufficient cash flow from operations, borrowings, or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions;
- lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling and completion techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services, and personnel;
- exploration and development risks;
- operational interruption of centralized gas and oil processing facilities;
- competition in the oil and natural gas industry;

- management's ability to execute our plans to meet our goals;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take-away capacity;
- our ability to secure adequate processing capacity for natural gas we produce, to secure adequate transportation for oil, natural gas, and natural gas liquids we produce, and to sell the oil, natural gas, and natural gas liquids at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East, South America, and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical, and technological factors that may negatively impact our businesses, operations, or pricing.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions, and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions, or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

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

"Analogous reservoir." Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

"Asset Sale." Any direct or indirect sale, lease (including by means of production payments and reserve sales and a sale and lease-back transaction), transfer, issuance, or other disposition, or a series of related sales, leases, transfers, issuances, or dispositions that are part of a common plan, of (a) shares of capital stock of a subsidiary, (b) all or substantially all of the assets of any division or line of business of the Company or any subsidiary, or (c) any other assets of the Company or any subsidiary outside of the ordinary course of business.

"Bbl." One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, or natural gas liquids.

"Bcf." One billion cubic feet of natural gas.

"Boe." One stock tank barrel of oil equivalent, calculated by converting natural gas and natural gas liquids volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

"British thermal unit" or *"BTU."* The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"*Basin.*" A large natural depression on the earth's surface in which sediments generally deposited via water accumulate.

"*Completion.*" The process of stimulating a drilled well followed by the installation of permanent equipment to allow for the production of crude oil and/or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Condensate.*" A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"*Developed acres.*" The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

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

"*Differential.*" The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead priced received.

"*Deterministic method.*" The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

"*Dry hole.*" Exploratory or development well that does not produce oil or gas in commercial quantities.

"*Economically producible.*" The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the cash costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

"*Environmental assessment.*" A study that can be required pursuant to federal law to assess the potential direct, indirect, and cumulative impacts of a project.

"*Estimated ultimate recovery (EUR).*" Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

"*Exploratory well.*" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"*Extension well.*" A well drilled to extend the limits of a known reservoir.

"*Field.*" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, laterally by local geologic barriers, or by 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.

"*Finding and development costs.*" Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

"*Formation.*" A layer of rock which has distinct characteristics that differ from nearby rock.

"*GAAP.*" Generally accepted accounting principles in the United States.

"*HH.*" Henry Hub index.

"*Gross Wells.*" The total wells in which an entity owns a working interest.

"*Horizontal drilling.*" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*Hydraulic fracturing.*" The process of injecting water, proppant, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production into the wellbore.

"*Infill drilling.*" The addition of wells in a field that decreases average well spacing.

"*LIBOR.*" London interbank offered rate.

"*LOE.*" Lease operating expense.

"*MBbl.*" One thousand barrels of oil or other liquid hydrocarbons.

"*MBoe.*" One thousand Boe.

"*Mcf.*" One thousand cubic feet.

"*MMBoe.*" One million Boe.

"*MMBtu.*" One million British Thermal Units.

"*MMcf.*" One million cubic feet.

"*Net acres.*" The percentage of total acres an owner has out of a particular number of acres or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"*Net production.*" Production that is owned by the registrant and produced to its interest, less royalties and production due others.

"*Net revenue interest.*" Economic interest remaining after deducting all royalty interests, overriding royalty interests, and other burdens from the working interest ownership.

"*Net well.*" Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.

"*NGL.*" Natural gas liquid.

"*NYMEX.*" The New York Mercantile Exchange.

"*Oil and gas producing activities.*" Defined as (i) the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations; (ii) the acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties; (iii) the construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as lifting the oil and gas to the surface and gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and (iv) extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coal beds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

"*PDNP.*" Proved developed non-producing reserves.

"*PDP.*" Proved developed producing reserves.

"*Percentage-of-proceeds.*" A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGLs, or a combination from the mineral owner in exchange for providing the processing services.

"*Play.*" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"*Plugging and abandonment.*" The sealing off of all gas and liquids in the strata penetrated by a well so that the gas and liquids from one stratum will not escape into another stratum or to the surface.

"*Pooling.*" Pooling, either contractually or statutorily through regulatory actions, allows an operator to combine multiple leased tracts to create a governmental spacing unit for one or more productive formations. Pooling is also known as unitization or communitization. Ownership interests are calculated within the pooling/spacing unit according to the net acreage contributed by each tract within the pooling/spacing unit.

"*Possible reserves.*" Those additional reserves that are less certain to be recovered than probable reserves.

"*Probable reserves.*" 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.

"*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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; (c) materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development, or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs identified above.

"*Productive well.*" An exploratory, development, or extension well that is not a dry well.

"*Proppant.*" Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"*Proved developed reserves.*" Proved reserves that can be 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 to the cost of a new well.

"*Proved reserves.*" 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 potions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

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

(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.

"Proved undeveloped reserves" or *"PUD."* Proved reserves 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. 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. 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 specific circumstances justify a longer time. Under no circumstances shall estimates for proved 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.

"PV-10." A non-GAAP financial measure that represents inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for differentials in location and quality) for each of the preceding twelve months. Please refer to footnote 2 of the Proved Reserves table in Item 1 of this Annual Report on Form 10-K for additional discussion.

"Reasonable certainty." If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"Reclamation." The process to restore the land and other resources to their original state prior to the effects of oil and gas development.

"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reserves." 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.

"Reserve replacement percentage." The sum of sales of reserves, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

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

"*Resource play.*" Drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

"*Royalty interest.*" An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas, or NGLs produced and sold unencumbered by expenses of drilling, completing, and operating of the well.

"*Sales volumes.*" All volumes for which a reporting entity is entitled to proceeds, including production, net to the reporting entity's interest and third party production obtained from percentage-of-proceeds contracts and sold by the reporting entity.

"*Service well.*" A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"*Spacing.*" Spacing as it relates to a spacing unit is defined by the governing authority having jurisdiction to designate the size in acreage of a productive reservoir along with the appropriate well density for the designated spacing unit size. Typical spacing for conventional wells is 40 acres for oil wells and 640 acres for gas wells. Typical spacing for unconventional wells is either 640 acres or 1,280 acres for both oil and gas.

"*Standard reach lateral equivalent well.*" Equates to a ratio of one well to one well for a standard reach lateral well, one and half wells to one well for a medium reach lateral well, and two wells to one well for an extended reach lateral well. Standard reach laterals typically include lengths of up to one mile, medium reach laterals of up to one and a half miles, and extended reach laterals of up to two miles.

"*Three stream.*" The separate reporting of NGLs extracted from the natural gas stream and sold as a separate product.

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

"*Undeveloped reserves.*" 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. Also referred to as "undeveloped oil and gas reserves."

"*Working interest.*" The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"*Workover.*" Operations on a producing well to restore or increase production.

"*WTI.*" West Texas Intermediate index.

PART I

Item 1. *Business*

When we use the terms “Bonanza Creek,” the “Company,” “we,” “us,” or “our,” we are referring to Bonanza Creek Energy, Inc. and its consolidated subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under *Glossary of Oil and Natural Gas Terms* above. Throughout this document, we make statements that may be classified as “forward-looking.” Please refer to the *Information Regarding Forward-Looking Statements* section above for an explanation of these types of statements.

Overview

Bonanza Creek is a Denver-based exploration and production company focused on the extraction of oil and associated liquids-rich natural gas in the Rocky Mountain region of the United States. Our development and extraction activities are primarily directed at the horizontal development of the Niobrara and Codell formations in the Denver-Julesburg (“DJ”) Basin. Bonanza Creek was incorporated in Delaware in 2010 and went public in 2011.

The Company's assets and operations are concentrated in the rural portions of unincorporated Weld County, Colorado, within the Wattenberg Field. We operate approximately 83% of all our productive wells, allowing us to control the pace, costs, and completion techniques used in the development of our reserves. The Wattenberg Field has a low cost structure, mature infrastructure, strong production efficiencies, multiple producing horizons, multiple service providers, established reserves, and prospective drilling opportunities, which helps facilitate predictable production and reserve growth.

The challenging commodity price environment that began in late 2014 and continued through 2017 improved marginally during 2018 and 2019. While commodity prices have improved slightly, they continue to be volatile. Nevertheless, we believe we remain well-positioned in this environment due to our healthy balance sheet, ample liquidity, inventory of economic drilling locations, low operating costs, and our operational flexibility, which allows us to respond to commodity price fluctuations.

During 2019, we demonstrated our operational focus on achieving best-in-class execution by lowering our cost of operations on a per unit basis. We increased drilling efficiencies and improved well performance via enhanced completion designs, which contributed to the growth of our reserves and production. Additionally, we maintained our conservative balance sheet and retained a modest level of borrowings on our reserve-based credit facility, thereby providing substantial available liquidity. We intend to continue our operational focus in 2020, emphasizing responsible growth and development, cost control, and full-cycle returns, with the intent to achieve cash flow neutrality. We will continue to monitor the ongoing commodity price and regulatory environment and expect to retain the operational flexibility to adjust our drilling and completion plans in response to such conditions.

Our Business Strategies

The Company’s primary objective is to maximize shareholder returns by responsibly developing our oil and gas resources. We seek to accomplish this through development of existing inventory and value-accretive acquisition and divestiture activity. We seek to balance production growth with maintaining a conservative balance sheet. Key aspects of our strategy include:

- *Multi-well pad development across our leasehold.* We believe horizontal development is the most efficient and safest way to recover the hydrocarbons located within our leasehold.
- *Enhanced completions.* We continuously evaluate completion designs to increase well productivity and apply a multivariate regression analysis with the objective of optimizing economic returns. Petrophysical, geological, and geophysical analysis is used in conjunction with spacing evaluations and individualized well designs to increase value of each spacing unit.
- *Continuous safety improvement and strict adherence to health and safety regulations.* Our goal is to utilize industry best practices to meet or exceed regulatory requirements and consistently engage stakeholders in our development planning and operations. We strive to maintain a safe workplace for our employees and contractors at all times.
- *Environmental stewardship.* We constantly strive to control and reduce emissions and seek to comply with all applicable air quality and other environmental rules and regulations. We employ best practices, including pipeline gathering and takeaway as well as vapor recovery and leak detection equipment. Additionally, we work closely with our service providers to help ensure they stay in compliance with environmental regulations when operating on our behalf.

- *Disciplined approach to acquisitions and divestitures.* Opportunities are evaluated in the context of maintaining development flexibility and a healthy balance sheet. We pursue value-accretive acquisitions and strive to maximize scale and minimize financial and operational risk.
- *Prudent risk management.* The Company believes a healthy balance sheet, focus on cost control, and minimizing long-term commitments are critical to controlling risk. A low debt profile and judicious use of hedging practices help reduce cash flow volatility. Continually striving to be a cost-efficient operator and maintaining a flexible capital spending program enable us to respond to changing market conditions.

Significant Developments in 2019

The Company further enhanced its gathering, treating, and production facilities, maintained under its Rocky Mountain Infrastructure, LLC (“RMI”) subsidiary, by installing a new oil gathering line in 2019 to Riverside Terminal, which resulted in a corresponding $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line. RMI provides many operational benefits to the Company and cost economies of a centralized system. The RMI system reduces gathering system pressures at the wellhead, thereby improving hydrocarbon recovery. Additionally, with eleven interconnects to four different natural gas processors, RMI helps ensure that the Company's production is not constrained by any single midstream service provider. Furthermore, the system reduces facility site footprints, leading to more cost-efficient operations and reduced surface disturbance. We will continue to look for ways to improve our access to gas gathering and processing services. The net book value of the Company's RMI assets was $147.8 million as of December 31, 2019.

The Company continued its development in the DJ Basin while testing enhanced completion designs on large, efficient multi-well pads throughout the Company’s acreage position. Enhanced completion designs varied to ensure that thorough knowledge could be applied to future drilling programs. Fluid volumes and types, proppant volumes and types, stage spacing, well spacing, and flowback techniques were the primary variables that were tested throughout the 2019 program. The Company will continue to monitor industry trends, public data, and information from non-operated wells to further define optimum completion techniques. We deployed one rig throughout the majority of 2019 and temporarily discontinued our use of the rig in late 2019 in response to the weakening commodity price environment. Sales volumes increased by approximately 37% when comparing the fourth quarters of 2019 and 2018.

The Company's 2019 capital program came in below original guidance at $222.2 million, while production came in higher than the midpoint of original guidance at 23.5 MBoe per day. During 2019, the Company drilled 59 gross operated wells, completed 40 gross operated wells, turned to sales 45 gross operated wells, and participated in the drilling and completion of five gross non-operated wells.

The following table summarizes our estimated proved reserves as of December 31, 2019:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed	25,397	105,840	11,566	54,603
Undeveloped	39,016	106,360	10,595	67,338
Total Proved	64,413	212,200	22,161	121,941

Total proved reserves as of December 31, 2019 increased by approximately 4% over the comparable period in 2018.

The following table summarizes our PV-10 reserve value, sales volumes, projected capital spend, and proved undeveloped drilling locations as of December 31, 2019:

Estimated Proved Reserves at December 31, 2019[1]			Average Net Daily Sales Volumes for the Year Ended December 31, 2019 (Boe/d)	Projected 2020 Capital Expenditures ($ in millions)	Gross Proved Undeveloped Drilling Locations as of December 31, 2019[3]
Total Proved (MBoe)	% Proved Developed	PV-10 ($ in MM)[2]			
121,941	45 %	$ 858.1	23,456	$ 215-235	274

(1) Proved reserves and related future net revenue and PV-10 were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices for each of the preceding twelve months, which were $55.85 per Bbl WTI and $2.58 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $4.63 per Bbl for crude oil and a decrease of $1.14 per MMBtu for natural gas.
(2) We believe that PV-10 provides useful and relevant information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies (specifically, the relative monetary significance of our reserves). Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating the Company and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. Please refer to the *Reconciliation of PV-10 to Standardized Measure* presented in the "Reserves" subsection of Item 1 below.
(3) The Company has 402.0 standard reach lateral equivalent gross proved undeveloped drilling locations as of December 31, 2019.

Our Operations

During 2019, our operations were solely focused in the rural portions of the Wattenberg Field in the Rocky Mountain region. The Company sold all of its assets within the Mid-Continent region and North Park Basin on August 6, 2018 and March 9, 2018, respectively.

Rocky Mountain Region

Our Rocky Mountain Region consists of one operating area in the Wattenberg Field in Weld County, Colorado. As of December 31, 2019, our estimated proved reserves were 121,941 MBoe and contributed 23,456 Boe/d of sales volumes during 2019.

Wattenberg Field - Weld County, Colorado. Our operations are located in the rural portions of the oil and liquids-weighted extension area of the Wattenberg Field targeting the Niobrara and Codell formations. As of December 31, 2019, our Wattenberg position consisted of approximately 92,000 gross (67,000 net) acres.

The Niobrara and Codell formations are now primarily developed using horizontal drilling and multi-stage fracture stimulation techniques. We believe the Niobrara B and C benches have been fully delineated on our legacy acreage, while the Codell formation has been delineated on our western legacy acreage. Our northern and southern acreage positions are currently being delineated.

As of December 31, 2019, we had a total of 678 gross producing wells, of which 539 were horizontal wells. Our sales volumes for the fourth quarter of 2019 were 24.3 MBoe per day. As of December 31, 2019, our working interest for all producing wells averaged approximately 79%, and our net revenue interest was approximately 64%.

We drilled and participated in drilling 91 gross (67.0 net) standard reach lateral ("SRL") equivalent wells in 2019 in the Wattenberg Field. As of December 31, 2019, we have an identified drilling inventory of approximately 274 gross (188.5 net) proved undeveloped ("PUD") drilling locations (402.0 gross SRL equivalents) on our acreage.

The following table summarizes our drilling and completion activity for SRL wells, medium reach lateral wells ("MRL"), and extended reach laterals wells ("XRL") on a gross basis for the year ended December 31, 2019.

	SRL		MRL		XRL	
	Drilled	Completed	Drilled	Completed	Drilled	Completed
Niobrara - Operated	35	13	—	7	23	19
Codell - Operated	—	—	—	—	1	1
Niobrara - Non-operated	2	2	—	—	3	3

North Park Basin - Jackson County, Colorado. We successfully sold all of our North Park assets on March 9, 2018 for minimal net proceeds and full release of all current and future obligations. Our North Park sales volumes for 2018, prior to the divestiture, were 10 Boe/d.

Mid-Continent Region

We successfully sold our Mid-Continent assets on August 6, 2018 for net proceeds of $103.5 million. We achieved a sales volume rate for 2018 of 1,728 Boe/d prior to the divestiture, or 10% of sales volume for 2018. At December 31, 2017, the Company had 300 gross producing vertical wells and proved reserves of approximately 10,419 MBoe.

Reserves

Estimated Proved Reserves

The summary data with respect to our estimated proved reserves presented below has been prepared in accordance with rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to companies involved in oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves. Our estimated proved reserves for the years ended December 31, 2019, 2018, and 2017 were determined using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices. For a definition of proved reserves under the SEC rules, please see the *Glossary of Oil and Natural Gas Terms* included in the beginning of this report.

Reserve estimates are inherently imprecise, and estimates for undeveloped properties are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, all of these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of our estimated proved reserves. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may vary from what we have estimated.

The table below summarizes our estimated proved reserves as of December 31, 2019, 2018, and 2017. The proved reserve estimates as of December 31, 2019, 2018, and 2017 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our third-party independent reserve engineers. For more information regarding our independent reserve engineers, please see *Independent Reserve Engineers* below. The information in the following table is not intended to represent the current market value of our proved reserves nor does it give any effect to or reflect our commodity derivatives or current commodity prices.

	As of December 31,		
Region/Field	**2019**	**2018**	**2017**
		(MMBoe)	
Rocky Mountain	**121.9**	**116.8**	**90.5**
Wattenberg	121.9	116.8	90.3
North Park	—	—	0.2
Mid-Continent	**—**	**—**	**11.5**
Dorcheat Macedonia	—	—	10.4
McKamie Patton	—	—	1.1
Total	**121.9**	**116.8**	**102.0**

The following table sets forth more information regarding our estimated proved reserves at December 31, 2019, 2018, and 2017:

	As of December 31,		
	2019	2018	2017
Reserve Data[1]:			
Estimated proved reserves:			
Oil (MMBbls)	64.4	64.4	52.9
Natural gas (Bcf)	212.2	165.0	157.7
Natural gas liquids (MMBbls)	22.2	24.9	22.8
Total estimated proved reserves (MMBoe)[2]	121.9	116.8	102.0
Percent oil and liquids	71 %	76 %	74 %
Estimated proved developed reserves:			
Oil (MMBbls)	25.4	23.7	25.8
Natural gas (Bcf)	105.8	79.6	92.7
Natural gas liquids (MMBbls)	11.6	11.7	12.7
Total estimated proved developed reserves (MMBoe)[2]	54.6	48.7	53.9
Percent oil and liquids	68 %	73 %	71 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	39.0	40.6	27.1
Natural gas (Bcf)	106.4	85.4	65.0
Natural gas liquids (MMBbls)	10.6	13.2	10.1
Total estimated proved undeveloped reserves (MMBoe)[2]	67.3	68.1	48.1
Percent oil and liquids	74 %	79 %	77 %

(1) Proved reserves were calculated using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices, which were $55.85 per Bbl WTI and $2.58 per MMBtu HH, $65.56 per Bbl WTI and $3.10 per MMBtu HH, and $51.34 per Bbl WTI and $2.98 per MMBtu HH for the years ended December 31, 2019, 2018, and 2017, respectively. Adjustments were made for location and grade.
(2) Determined using the ratio of 6 Mcf of natural gas to one Bbl of crude oil.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves 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. Proved undeveloped 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 productivity at greater distances.

Proved undeveloped locations in our December 31, 2019 reserve report are included in our development plan and are scheduled to be drilled within five years from the year they were initially recorded. The Company's management evaluated the proved undeveloped drilling plan using the most recently supported type curves, NYMEX strip prices, the liquidation model for general and administrative costs, updated capital expenditures and lease operating costs to match revised bids and actuals from year-end. The reserve report factored in a one-and-a-half rig program starting in 2020 and increasing to a two-rig program in the second half of 2022, which results in all PUDs being drilled within the allotted five-year window. We typically book proved undeveloped locations within one development spacing area from developed producing locations. For the instances where a proved undeveloped location is beyond one spacing area from a developed producing location, we utilized reliable geologic and engineering technology. The reliable technologies used to establish our proved reserves are a combination of pressure performance, geologic mapping, offset productivity, electric logs, seismic, and production data.

As of December 31, 2019, we had 274.0 gross (402.0 SRL equivalents) proved undeveloped locations compared to 300.0 gross (444.5 SRL equivalents) for the comparable period in 2018. Of the total gross proved undeveloped locations at December 31, 2019, approximately 84% and 16% are scheduled to be drilled at 8-12 wells per section and 14+ wells per section, respectively. Wells per section are estimated based on equivalent spacing between wells for a 640-acre section.

Total estimated proved reserves at December 31, 2019 increased 4% to 121.9 MMBoe when compared to December 31, 2018. The net increase in proved reserves of 5.1 MMBoe was the result of promoting 15.0 MMBoe of PUDs, adding 8.1 MMBoe of engineering revisions, adding 0.4 MMBoe of acquired reserves, adding 0.3 MMBoe of converted producing properties from unproven locations, offset by demoting 8.7 MMBoe of PUDs, producing 8.6 MMBoe of reserves, and removing 1.4 MMBoe due to reduced pricing.

The 15.0 MMBoe in PUD promotions was the result of converting 47 operated horizontal locations in the Niobrara and Codell formations in the Wattenberg Field to proved reserves during 2019 and adding infill and extension PUD locations due to the 2020 rig program. The 8.7 MMBoe of PUD demotions is due to those locations being removed from the five-year drilling program. The negative pricing revision of 1.4 MMboe resulted from a decrease in average commodity price from $65.56 per Bbl WTI and $3.10 per MMBtu HH for the year ended December 31, 2018 to $55.85 per Bbl WTI and $2.58 per MMBtu HH for the year ended December 31, 2019.

Reconciliation of Proved Reserves PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Neither our PV-10 measure or the Standardized Measure purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to Standardized Measure at December 31, 2019, 2018, and 2017 (in millions):

	December 31,		
	2019	2018	2017
PV-10	$ 858.1	$ 955.0	$ 598.5
Present value of future income taxes discounted at 10%(1)	—	—	—
Standardized Measure	$ 858.1	$ 955.0	$ 598.5

(1) The tax basis of our oil and gas properties as of December 31, 2019, 2018 and 2017 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using $55.85 per Bbl WTI and $2.58 per MMBTU HH, $65.56 per Bbl WTI and $3.10 per MMBtu HH, and $51.34 per Bbl WTI and $2.98 per MMBtu HH, respectively.

Proved Undeveloped Reserves

	Net Reserves (MBoe) As of December 31, 2019
Beginning of year	68,086
Converted to proved developed	(11,696)
Additions from capital program	15,040
Removed from capital program	(8,706)
Acquisitions, net	259
Revisions	4,355
End of year	67,338

As of December 31, 2019, our proved undeveloped reserves were 67,338 MBoe, all of which are scheduled to be drilled within five years from the year they were initially recorded. During 2019, the Company converted 17% of its proved undeveloped reserves, which is comprised of 47 gross wells representing net reserves of 11,696 MBoe, at a cost of $178.2 million. The net increase of 15,040 MBoe in PUD additions is the result of adding 46 SRL and 8 XRL infill PUD locations in the areas that are captured in our five-year drilling program. The net decrease of 8,706 MBoe in PUD demotions is the result of removing 32 PUD locations as they were no longer part of our five-year drilling program.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company’s Reserves Committee reviews significant reserve changes on an annual basis and our third-party independent reserve engineers, NSAI, is engaged by and has direct access to the Reserves Committee. The reserves estimates for the year ended December 31, 2019, 2018, and 2017 shown herein have been independently prepared by NSAI. These NSAI reserve estimates are reviewed by our in-house petroleum engineer who oversees and controls preparation of the reserve report data by working with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI for their evaluation process. The Company's technical person who was primarily responsible for overseeing the preparation of our reserve estimates was our Senior Reservoir Engineer who has 15 years of experience in the oil and gas industry, including 3 years in their role at the Company. Their professional qualifications include a bachelor's degree in Chemical Engineering from the Colorado School of Mines.

Independent Reserve Engineers

The reserves estimates shown herein for December 31, 2019, 2018, and 2017 have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Benjamin W. Johnson and Mr. John G. Hattner. Mr. Johnson, a Licensed Professional Engineer in the State of Texas (No. 124738), has been practicing consulting petroleum engineering at NSAI since 2007 and has over 2 years of prior industry experience. He graduated from Texas Tech University in 2005 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geophysics (No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991, and has over 11 years of prior industry experience. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration Degree. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production, Revenues and Price History

Oil and gas prices fluctuated moderately during 2019. Oil prices are impacted by production levels, crude oil inventories, real or perceived geopolitical risks in oil producing regions, the relative strength of the U.S. dollar, weather, and the global economy. During periods of favorable pricing, we expect increased industry activity, which could moderate the magnitude of price increases throughout the year.

Sensitivity Analysis

If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 0.3% and our PV-10 value as of December 31, 2019 would decrease by approximately 24% or $203.3 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 0.7% and our PV-10 value as of December 31, 2019 would increase by approximately 22% or $186.4 million.

Production

The following table sets forth information regarding oil, natural gas, and natural gas liquids production, sales prices, and production costs for the periods indicated. For additional information on price calculations, please see information set forth in *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	Successor			Predecessor
	For the Year Ended December 31, 2019	For the Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Oil:				
Total Production (MBbls)	5,135.9	3,840.8	2,012.7	1,068.5
Wattenberg Field	5,135.9	3,500.2	1,568.5	834.4
Dorcheat Macedonia Field	—	340.6	379.9	193.2
Average sales price (per Bbl), including derivatives[3]	$ 52.12	$ 54.77	$ 46.44	$ 48.29
Average sales price (per Bbl), excluding derivatives[3]	$ 51.89	$ 59.38	$ 47.18	$ 48.29
Natural Gas:				
Total Production (MMcf)	11,966.8	8,591.2	5,767.5	3,242.5
Wattenberg Field	11,966.8	7,408.3	4,588.1	2,564.9
Dorcheat Macedonia Field	—	1,182.8	1,179.3	677.6
Average sales price (per Mcf), including derivatives[4]	$ 2.10	$ 2.39	$ 2.29	$ 2.57
Average sales price (per Mcf), excluding derivatives[4]	$ 2.06	$ 2.45	$ 2.29	$ 2.57
Natural Gas Liquids:				
Total Production (MBbls)	1,431.1	1,141.2	712.9	422.7
Wattenberg Field	1,431.1	1,048.3	656.2	391.1
Dorcheat Macedonia Field	—	92.8	56.8	31.6
Average sales price (per Bbl), including derivatives	$ 11.22	$ 22.46	$ 18.38	$ 17.52
Average sales price (per Bbl), excluding derivatives	$ 11.22	$ 22.46	$ 18.38	$ 17.52
Oil Equivalents:				
Total Production (MBoe)	8,561.5	6,413.8	3,686.9	2,031.6
Wattenberg Field	8,561.5	5,783.2	2,989.4	1,653.0
Dorcheat Macedonia Field	—	630.6	633.2	337.7
Average Daily Production (Boe/d)	23,456.2	17,572.0	15,048.4	16,930.4
Wattenberg Field	23,456.2	15,844.0	12,201.5	13,774.9
Dorcheat Macedonia Field	—	1,728.0	2,584.5	2,814.3
Average Production Costs (per Boe)[1][2]	$ 4.35	$ 7.11	$ 9.28	$ 8.20

(1) Excludes ad valorem and severance taxes.

(2) Represents lease operating expense and gas plant and midstream operating expense per Boe using total production volumes. Total production volumes exclude volumes from our percentage-of-proceeds contracts in our Mid-Continent region of 65.0 MBoe, 77.9 MBoe, and 41.9 MBoe for the year ended December 31, 2018, the 2017 Successor Period, and the 2017 Predecessor Period, respectively. The Mid-Continent region assets were sold August 6, 2018, and therefore, no sales volumes were associated with the Mid-Continent region during the year ended December 31, 2019.

(3) Crude oil sales excludes $2.4 million, $0.6 million, $0.2 million, and $0.1 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period, respectively.

(4) Natural gas sales excludes $3.7 million, $1.3 million, $0.8 million, and $0.4 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period, respectively.

Principal Customers

One of our customers, NGL Crude Logistics, LLC (“NGL Crude”) comprised 82% of our total revenue for the year ended December 31, 2019. No other single non-affiliated customer accounted for 10% or more of our oil and natural gas sales in 2019. We believe the loss of any one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers for our product.

Delivery Commitments

The purchase agreement to deliver fixed determinable quantities of crude oil to NGL Crude became effective on April 28, 2017. The NGL Crude agreement includes defined volume commitments over an initial seven-year term. Under the terms of the NGL Crude agreement, the Company will be required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments, which are set in six-month periods beginning in January 2018. During 2018, the average minimum gross volume commitment was approximately 10,100 barrels per day, and the minimum gross volume commitment increased by approximately 41% from 2018 to 2019 and will increase approximately 3% each year thereafter for the remainder of the contract, to a maximum of approximately 16,000 gross barrels per day. The aggregate financial commitment fee over the remaining term, based on the minimum gross volume commitment schedule (as defined in the agreement) and the applicable differential fee, is $81.0 million as of December 31, 2019. Please refer to *Part II, Item 8, Note 7 - Commitments and Contingencies* for additional discussion.

Productive Wells

The following table sets forth the number of producing oil and natural gas wells in which we owned a working interest at December 31, 2019.

	Oil(2)		Natural Gas(1)		Total(2)		Operated(2)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	678	534.5	—	—	678	534.5	566	516.1

(1) All gas production is associated gas from producing oil wells.
(2) Count was obtained from internal production reporting system.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2019, along with the PV-10 value. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres		
	Gross	Net	Gross	Net	Gross	Net	PV-10
Rocky Mountain	66,808	55,423	24,823	11,317	91,631	66,740	$ 858.1

Undeveloped acreage

We critically review and consider at-risk leasehold with attention to our ability either to convert term leasehold to held-by-production status or obtain term extensions. Decisions to let leasehold expire generally relate to areas outside of our core area of development or when the expirations do not pose material impacts to development plans or reserves.

The following table sets forth the number of net undeveloped acres as of December 31, 2019 that will expire over the next three years unless production is established within the spacing units covering the acreage or the applicable leases are extended prior to the expiration dates:

	Expiring 2020		Expiring 2021		Expiring 2022	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	7,490	2,669	3,203	1,880	938	1,448

Drilling Activity

The following table sets forth the exploratory and development wells completed (operated and non-operated) during the years ended December 31, 2019, 2018, and 2017.

	For the Years Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive Wells	—	—	—	—	—	—
Dry Wells	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Development						
Productive Wells	45	34.1	56	43.8	36	16.0
Dry Wells	—	—	—	—	—	—
Total Development	45	34.1	56	43.8	36	16.0
Total	45	34.1	56	43.8	36	16.0

The following table describes the present operated drilling activities as of December 31, 2019.

	As of December 31, 2019	
	Gross	Net
Exploratory	—	—
Development	42	32.6
Total	42	32.6

Capital Expenditure Budget

The Company's 2020 capital budget of $215 million to $235 million assumes the continuation of a one-rig operated program in the Company's legacy acreage and the startup of a one-rig non-operated program in the Company's French Lake area in late 2020. The Company's 2020 capital expenditures guidance includes $20 million to $25 million for non-operated capital, which includes approximately $10 million to $15 million for French Lake. The budget includes the drilling of 61 gross wells, completion of 45 gross wells, and turning to sales of 62 gross wells. Actual capital expenditures could vary significantly based on, among other things, changes in the operator’s development pace in French Lake, market conditions, commodity prices, drilling and completion costs, well results, and changes in the borrowing base under our Credit Facility (defined below).

Derivative Activity

In addition to supply and demand, oil and gas prices are affected by seasonal, economic, local and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows through the use of derivative contracts. Oil revenue represented approximately 85% of our oil and gas sales in 2019. We have successfully hedged approximately 57% and 58% of our average 2020 guided oil production as of December 31, 2019 and as of the filing date of this report, respectively.

As of December 31, 2019, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG Basis)		Natural Gas (CIG)	
	Bbls/day	**Weighted Avg. Price per Bbl**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**
1Q20								
Cashless Collar	5,000	$55.00/$62.88	—	—	—	—	—	—
Swap	4,500	$60.69	20,000	$2.63	20,000	$0.56	2,500	$2.40
2Q20								
Cashless Collar	7,500	$54.00/$61.01	—	—	—	—	—	—
Swap	1,500	$54.98	10,000	$2.61	20,000	$0.56	—	—
3Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,000	$53.60	—	—	20,000	$0.56	—	—
4Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,000	$53.60	—	—	20,000	$0.56	—	—
1Q21								
Cashless Collar	2,000	$50.50/$55.19	—	—	—	—	—	—
Swap	3,500	$53.89	—	—	—	—	—	—
2Q21								
Cashless Collar	500	$52.00/$55.00	—	—	—	—	—	—
Swap	2,000	$53.35	—	—	—	—	—	—
3Q21								
Swap	1,000	$54.87	—	—				

As of the filing date of this report, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG Basis)		Natural Gas (CIG)	
	Bbls/day	**Weighted Avg. Price per Bbl**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**	**MMBtu/day**	**Weighted Avg. Price per MMBtu**
1Q20								
Cashless Collar	5,000	$55.00/$62.88	—	—	—	—	—	—
Swap	4,500	$60.69	20,000	$2.63	26,593	$0.55	2,500	$2.40
2Q20								
Cashless Collar	7,500	$54.00/$61.01	—	—	—	—	—	—
Swap	1,500	$54.98	10,000	$2.61	30,000	$0.54	—	—
3Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,500	$54.12	—	—	30,000	$0.54	—	—
4Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,500	$54.12	—	—	30,000	$0.54	—	—
1Q21								
Cashless Collar	2,000	$50.50/$55.19	—	—	—	—	—	—
Swap	5,000	$54.48	—	—	—	—	—	—
2Q21								
Cashless Collar	500	$52.00/$55.00	—	—	—	—	—	—
Swap	4,000	$54.13	—	—	—	—	—	—
3Q21								
Swap	2,500	$54.45	—	—	—	—	—	—
4Q21								
Swap	1,000	$55.20	—	—	—	—	—	—

Bankruptcy Proceedings under Chapter 11

On January 4, 2017, the Company and all of its direct and indirect subsidiaries (collectively, the "Debtors") filed voluntary petitions under Chapter 11 in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). The Debtors received bankruptcy court confirmation of their *Third Amended Joint Prepackaged Plan of Reorganization*, dated April 6, 2017 (the "Plan"), and emerged from bankruptcy on April 28, 2017 (the "Effective Date"). For additional information about our bankruptcy proceedings and emergence, please refer to *Part II, Item 8, Note 14 - Chapter 11 Proceedings and Emergence*.

Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date, which differed materially from the recorded values of those same assets and liabilities in the Predecessor Company. As a result, our balance sheets and statement of operations subsequent to the Effective Date are not comparable to our balance sheets and statements of operations prior to the Effective Date. For additional information about our application of fresh-start accounting, please refer to *Part II, Item 8, Note 15 - Fresh-Start Accounting.*

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to April 28, 2017. References to "2017 Successor Period" relate to the period of April 29, 2017 through December 31, 2017. References to the "2017 Predecessor Period" relate to the period of January 1, 2017 through April 28, 2017.

Title to Properties

Our properties are subject to customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, other industry-related constraints, and certain other leasehold restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we have satisfactory title to all of our producing properties. We undergo a thorough title review process upon receipt of title opinions prepared by outside legal counsel before we commence drilling operations. Although title to our properties is subject to complex interpretation of multiple conveyances, deeds, reservations, and other instruments that serve to affect mineral title, we believe that none of these risks will materially detract from the value of our properties or from our interest therein or otherwise materially interfere with the operation of our business.

Competition

The oil and natural gas industry is highly competitive, and we compete with a substantial number of other companies that often have greater resources. Many of these companies explore for, produce, and market oil and natural gas, carry on refining operations, and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, attracting and retaining qualified personnel, and obtaining transportation for the oil and gas we produce. There is also competition between producers of oil and gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state, and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing, or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect and potential impacts of these risks are difficult to accurately predict.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 71% of our estimated proved reserves as of December 31, 2019 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2019, the daily NYMEX WTI oil spot price ranged from a high of $66.24 per Bbl to a low of $46.31 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $4.25 per MMBtu to a low of $1.75 per MMBtu.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business, either because such insurance is not available or customary, or because premium costs are considered cost prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, or cash flows.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state, and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes, and numerous other laws and regulations. The jurisdiction in which we own and operate properties or assets for oil and natural gas production has statutory provisions regulating the exploration for and production of oil and natural gas, including, among other things, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells and pipelines. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations. The regulatory burden on the industry can increase the cost of doing business and negatively affect profitability. Because such laws and regulations are frequently revised and amended through various legislative actions and rulemakings, it is difficult to predict the future costs or impact of compliance. Additional rulemakings that affect the oil and natural gas industry are regularly considered at the federal, state, and various local government levels, including statutorily and through powers granted to various agencies that regulate our industry, and various court actions. We cannot predict when or whether any such rulemakings may become effective or if the outcomes will negatively affect our operations.

We believe that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows, or results of operations. However, current regulatory requirements may change, currently unforeseen incidents may occur, or past noncompliance with laws or regulations may be discovered, any of which could have a material adverse effect on our financial position, cashflows, or results of operations.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state, and federal statutes, rules, orders, and regulations. Federal, state, and local statutes and regulations require, among other things, permits for drilling operations, drilling bonds, and reports concerning operations. Colorado, the state in which we own and operate all of our properties, has regulations governing conservation matters, including provisions for the spacing and unitization or pooling of oil and natural gas properties, the regulation of well spacing and well density, and procedures for proper plugging and abandonment of wells and associated facilities. These regulations effectively identify well densities by geologic formation and the appropriate spacing and pooling unit size to effectively drain the resources. Operators can apply for exceptions to such regulations, including applications to increase well densities to more effectively recover the oil and gas resources. Moreover, Colorado imposes a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within its jurisdiction.

We own interests in properties located onshore in one U.S. state, Colorado. This state regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Colorado laws also govern a number of environmental and conservation matters, including the handling and disposal of waste materials, prevention of excessive flaring, air pollutant emissions permitting, the size of drilling and spacing units or proration units, the density of wells that may be drilled, and the unitization and pooling of oil and gas properties.

Regulation of transportation of oil

Our sales of crude oil are affected by the availability, terms, and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as “petroleum pipelines”), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is materially different from how it affects operations of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act (“NGPA”) and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act (“NGA”), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

FERC issued a series of orders in 1996 and 1997 to implement its open access policies. As a result, the interstate pipelines’ traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC’s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici Barton Energy Policy Act of 2005 (“EP Act of 2005”) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC’s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation more accessible to natural gas services subject to the jurisdiction of FERC, for any entity, directly or indirectly, (1) to use or employ any device, scheme, or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases, or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

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, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental, and, in some circumstances, nondiscriminatory-take requirements. Although nondiscriminatory-take regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts, or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act (“CEA”), and regulations promulgated thereunder by the Commodity Futures Trading Commission (“CFTC”). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity.

The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in the state in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is materially different from how it affects operations of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers, and marketers with which we compete.

Regulation of derivatives

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was passed by Congress and signed into law in July 2010. The Dodd-Frank Act is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users.

Environmental, Health and Safety Regulation

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, state, and local laws and regulations governing safety and health, the discharge of materials into the environment, or otherwise relating to protection of the environment or natural resources, noncompliance with which can result in substantial administrative, civil, and criminal penalties and other sanctions, including suspension or cessation of operations. These laws and regulations may, among other things, require the acquisition of permits before drilling or other regulated activity commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities that have certain impacts or that occur in certain areas; require some form of investigation or remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker, public health, and natural resource protection and impose substantial liabilities for unpermitted pollutant emissions resulting from operations or failure to comply with regulatory filing obligations. Cumulatively, these laws and regulations may impact our rate of production.

The following is a summary of the more significant existing environmental and health and safety laws and regulations to which we are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations, or financial position.

Air emissions

The Clean Air Act (“CAA”) and comparable state laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification and operation of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining required air permits can significantly delay the development of certain oil and natural gas projects. Over the next several years, we may be required to incur certain expenditures for air pollution control equipment or other air emissions-related issues.

For example, on August 16, 2012, the Environmental Protection Agency (the “EPA”) published final rules under the CAA that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. These regulations establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from certain pneumatic controllers and storage vessels. The EPA issued revised rules in 2013 and 2014 in response to requests for reconsideration of portions the 2012 NSPS and NESHAP rules from industry and the environmental community. In May 2016, the EPA issued additional New Source Performance Standards (“NSPS”) rules focused on achieving additional methane and volatile organic compound reductions from oil and natural gas operations. Among other things, these revisions impose new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. EPA proposed further revisions to the NSPS rules based on additional requests for reconsideration on October 15, 2018, and again on September 24, 2019, intended to revisit prior source category determinations and parts of the 2016 rules, including whether to regulate methane or just regulate volatile organic compound emissions with the same methane emission reductions as co-benefits. The proposed revisions also address certain technical issues raised in administrative petitions and include proposed changes to, among other things, the frequency for monitoring fugitive emissions at well sites and compressor stations.

In February 2014, the Colorado Department of Public Health and Environment’s Air Quality Control Commission (“AQCC”) adopted new and revised air quality regulations that impose stringent new requirements to control emissions from both existing and new or modified oil and gas facilities in Colorado. The regulations include new emissions control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in Colorado. For example, the regulations impose Storage Tank Emission Management (“STEM”) requirements for certain new and existing storage tanks. The STEM requirements require us to install costly emission control technologies as well as monitoring and recordkeeping programs at most of our new and existing well production facilities. The new Colorado regulations also impose a Leak Detection and Repair (“LDAR”) program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado and represents a significant new use of state authority regarding these emissions. In December 2019, the AQCC adopted new and revised air quality regulations that extend the controls adopted in 2014 to many lower producing and emitting facilities statewide, and add storage tank loadout controls to those requirements, among other changes. The new rules also increase the frequency of LDAR monitoring to semi-annual for lower producing facilities previously subject to a one-time monitoring requirement, as well as require monthly LDAR monitoring for facilities within 1,000 ft. of occupied areas, and impose a new emission inventory and reporting of green house gases (“GHGs”), among other requirements. These new requirements become effective as early as January 30, 2020, with some requiring compliance by May 1, 2020, or May 1, 2021.

In October 2015, EPA finalized its rule lowering the existing 75 part per billion (“ppb”) national ambient air quality standard (“ 2008 NAAQS”) for ozone under the CAA to 70 ppb (“2015 NAAQS”). Also in 2019, the state of Colorado’s Denver Metro and North Front Range (“DM/NFR”) air quality control region received a bump-up in its existing non-attainment status for the 2008 NAAQS from “moderate” to “serious.” Oil and natural gas operations in ozone non-attainment areas, including in the DM/NFR area, may be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. A “serious” classification triggers significant additional obligations for the state under the CAA and will result in new and more stringent air quality control requirements applicable to our operations and significant operating costs and delays in obtaining necessary permits for new and modified production facilities.

In May 2016, the EPA also finalized a rule regarding source determination, including defining the term “adjacent” under the CAA, which affects how major sources are defined, particularly regarding criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed major sources, thereby triggering more stringent air permitting requirements. These EPA rulemakings will have nominal effect on our operations, because the rule clarified our existing presumption on “adjacent” and presents no conflict with the state of Colorado definitions.

The EPA also published Control Technique Guidelines (“CTGs”) in October 2016 aimed at providing states with guidance and setting a presumptive floor for Reasonably Achievable Control Technology (“RACT”) for the oil and gas industry in areas of ozone non-attainment, including the DM/NFR area. In November 2017, as required following issuance of the CTGs, the Colorado Air Quality Control Commission AQCC adopted additional RACT and other air quality regulations that increased emissions control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in the DM/NFR area, and to some extent state-wide.

Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Government authorities frequently add to those requirements, and both oil and gas development generally and hydraulic fracturing specifically are receiving increasing regulatory attention. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

States have historically regulated oil and gas exploration and production activity, including hydraulic fracturing. State governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration, the disclosure of the chemicals used in fracturing, or other matters. Colorado, for example, requires operators to reduce hydrocarbon emissions associated with hydraulic fracturing, compile and report additional information regarding wellbore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, maintain minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, and implement additional groundwater testing. Colorado has also imposed additional permitting requirements for certain large scale facilities in urban mitigation areas and additional notice requirements prior to engaging in operations near certain municipalities. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions to our operations.

The federal Safe Drinking Water Act (“SDWA”) and comparable state statutes may restrict the disposal, treatment, or release of water produced or used during oil and gas development. Subsurface emplacement of fluids, primarily via disposal wells or enhanced oil recovery (“EOR”) wells, is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state’s environmental authority. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of “underground injection,” but disposal of hydraulic fracturing fluids and produced water or their injection for EOR is not excluded.

Federal agencies have periodically considered additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. As noted above, in June 2016, EPA finalized regulations that address discharges of wastewater pollutants from onshore unconventional extraction facilities to publicly-owned treatment works. The EPA also published a study of the impact of hydraulic fracturing on drinking water resources in December 2016, which concluded that drinking water resources can be affected by hydraulic fracturing under specific circumstances. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. As also noted above, in January 2017, the EPA issued a proposed rule to include natural gas processing facilities in the Toxic Release Inventory (“TRI”) program. The United States Department of the Interior also finalized a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity, and handling of flowback water; however, on December 29, 2017, the BLM issued a rescission of the hydraulic fracturing rule. This rescission and the rule as promulgated are subject to ongoing litigation. Additionally, in early 2016, the Bureau of Land Management (“BLM”) proposed rules related to further controlling the venting and flaring of natural gas on BLM land. On September 28, 2018, the BLM published a final rule that revises the 2016 rules. The new rule, among other things, rescinds the 2016 rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels, and leak detection and repair. The new rule also revised provisions related to venting and flaring. Environmental groups and the states of California and New Mexico have filed challenges to the 2018 rule in the United States District Court for the Northern District of California.

Apart from these ongoing federal and state initiatives, some state and local governments have adopted their own new requirements on hydraulic fracturing and other oil and gas operations. Voters in Colorado have proposed or advanced initiatives restricting or banning oil and gas development in Colorado, but these initiatives have failed to date. Any successful bans or moratoriums where we operate could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations. In addition, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could have a material adverse effect on our business.

At this time, it is not possible to estimate the potential impact on our business of recent state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing. The adoption of future federal, state, or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in the Rocky Mountain region.

Typical hydraulic fracturing treatments are made up of water, chemical additives, and sand. We utilize major hydraulic fracturing service companies who track and report additive chemicals that are used in fracturing as required by the appropriate government agencies, including FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Each of the service companies we use fracture stimulate a multitude of wells for the industry each year.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. Our operations are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), who frequently inspect our fracturing operations.

Other State Laws

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission (the “COGCC”), as well as other state agencies. The COGCC finalized new flowline rules in February 2018. The new rules include: increased registration requirements, flowline design requirements, integrity management requirements, and leak detection programs, and requirements for abandoned flowlines. In November 2019, the COGCC further amended its flowline rules to impose additional requirements regarding flowline mapping, operational status, certification, and abandonment, among other things. Over the past several years, the COGCC has also approved new rules regarding various other matters, including wellbore integrity, hydraulic fracturing, well control, waste management, spill reporting, spacing of wells and pooling of mineral interests, and an increase in potential sanctions for COGCC rule violations. Additionally, the COGCC approved rules regarding minimum setbacks, groundwater monitoring, large-scale facilities in urban mitigation areas, and public notice requirements that are intended to prevent or mitigate environmental impacts of oil and gas development. In December 2019, the COGCC proposed new regulations to further enhance wellbore integrity and improve safety and environmental protection during hydraulic fracturing. Depending on how these and any other new rules are applied, they could add substantial increases in well costs for our Colorado operations. The rules could also impact our ability to operate and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets.

In 2016, the Colorado Supreme Court ruled that the cities of Fort Collins and Longmont do not have authority to ban oil and gas operations within their jurisdictional limits. Although we do not own or lease minerals or operate within any of these municipal areas, the Colorado Supreme Court decision has bearing on our ability to continue to operate in Colorado. Further, Weld County completed implementation of a revised local government permitting process for land use approval, and Boulder County substantially revised its oil and gas regulations. We do not expect that these local government regulations will have any material impact on our operations.

On April 16, 2019, new legislation became effective in Colorado, which substantially changes the state’s regulation of oil and gas exploration and production activities, and applies immediately to all pending permit applications. The new law changes the COGCC's mission from “fostering” responsible and balanced development to “regulating” public health and the environment. The required composition of the COGCC was changed to remove two seats for industry experts and add experts on wildlife/environmental protection and public health. The state’s statutory pooling provisions were also changed by the new law to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required.

Among the most significant changes under the legislation was the provision of local government control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions.

The legislation mandates COGCC rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. Pending the completion of this initial rulemaking, the COGCC may delay acting on selected permit applications. The COGCC completed rulemaking on flowlines in November 2019, initiated rulemaking on wellbore integrity in December 2019, and announced plans to undertake rulemaking on the “mission change,” facility siting, and cumulative impacts during the first half of 2020. According to the COGCC, the mission change rulemaking may address a wide range of topics including development approvals, asset transfers, pollution standards, flaring restrictions, spill reporting, and cleanup responsibility.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds and nitrogen oxides associated with certain oil and gas facilities. The AQCC adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, and expanded storage tank control requirements and loadout control requirements statewide in December 2019. The AQCC may also adopt requirements for installation of continuous emission monitoring equipment at certain oil and gas facilities, and reduced emissions from pneumatic devices in future rulemaking scheduled for late 2020. The legislation also grants the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling and completion.

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original 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 occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as or contain CERCLA hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes, and distinguishes between hazardous and non-hazardous or solid wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent hazardous waste requirements, while all states regulate solid waste. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development, and production of natural gas and oil are currently regulated under RCRA's non-hazardous waste provisions and state solid waste laws. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent handling, disposal, and clean-up requirements. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that seeks to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. On December 28, 2016, the EPA entered into a consent decree with those environmental groups to settle the lawsuit, which required the EPA by March 15, 2019 to either propose new regulations regarding exploration and production related wastes or sign a determination that revision of such regulations is not necessary. Pursuant to the consent decree, EPA determined in April 2019 that revision of the regulations is unnecessary. EPA indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development, and production wastes continue to be managed in a manner that protects human health and the environment. Environmental groups, however, expressed dissatisfaction with EPA's decision and will likely continue to press the issue at the federal and state levels.

In 2018, the Colorado State legislature passed Senate Bill 245 that gave the Colorado Department of Public Health & Environment ("CDPHE") the authority to promulgate rules for the safe management of Technologically Enhanced Naturally Occurring Radioactive Material ("TENORM"). TENORM is naturally occurring radioactive material whose radionuclide concentrations are increased through human activity, such as through generation of water treatment residuals, scales and sediments from oil and gas production, and other processes. The bill requires the Department to review TENORM residual management and regulatory limits from other states as well as prepare a report that considers background radiation levels in the state, waste stream identification and quantification, use and disposal practices, current engineering practices, appropriate test methods, economic impacts, and data gaps. This work was completed by CDPHE in 2019. During 2020, CDPHE expects to promulgate new rules governing TENORM waste, which would become effective during 2021. During drilling, completion, and production, numerous waste streams that may contain TENORM are created that are hauled for disposal at permitted disposal facilities. Depending on the final waste streams chosen for characterization and regulatory levels set for disposal, costs for characterization, storage, and disposal of waste could significantly increase.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore for and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, exploration and production fluids and gases may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators), to pay for damages for the loss or impairment of natural resources, and to take measures to prevent future contamination from our operations.

In addition, other laws require the reporting on use of hazardous and toxic chemicals. For example, in October 2015, EPA granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under the Toxic Release Inventory ("TRI") program under the Emergency Planning and Community Right-to-Know Act. EPA determined that natural gas processing facilities may be appropriate for addition to TRI applicable facilities and in January 2017, EPA issued a proposed rule to include natural gas processing facilities in the TRI program. EPA review of comments on this proposed rule is ongoing.

Pipeline safety and maintenance

Pipelines, gathering systems, and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant penalties, liability for natural resources damages, and significant business interruption. The U.S. Department of Transportation has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection, and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has issued new rules to strengthen federal pipeline safety enforcement programs. In 2015, PHMSA proposed to expand its regulations in a number of ways, including through the increased regulation of gathering lines, even in rural areas. In 2016, PHMSA increased its regulations to require crude oil sampling and reporting as an "offeror" (as defined under the PHMSA) and increased its civil penalty structure.

In Colorado, the Public Utilities Commission ("PUC") issued a notice of proposed rulemaking to amend its Rules Regulating Pipeline Operators and Gas Pipeline Safety for intrastate pipelines on December 31, 2019. The scope of the proposed rules includes all gas public utilities, all municipal or quasi-municipal corporations transporting natural gas or providing natural gas services, all operators of master meter systems, and all operators of pipelines transporting gas in intrastate commerce including gas gathering system operators (certain provisions are tailored to the location and size of the gathering systems involved). The proposed rules would require all filed reports to be publicly available and that all Notices of Proposed Violation, Notices of Action, pleadings and decisions to be filed publicly. The proposed rules also provide a revised methodology for calculating civil penalties in an effort to provide clarity to both operators and the public. The proposed rules will be the subject of an Administrative Law Judge hearing on February 10, 2020.

Climate change

Based on EPA findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment, the EPA adopted regulations under the CAA that, among other things, established Prevention of Significant Deterioration ("PSD"), construction, and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already major sources of emissions of regulated pollutants. In a subsequent ruling, the U.S. Supreme Court upheld a portion of EPA's GHG stationary source program, but also invalidated a portion of it, holding that stationary sources already subject to the PSD or Title V program for non-GHG criteria pollutants remained subject to GHG BACT requirements, but that sources subject to the PSD or Title V program only for GHGs could not be forced to comply with EPA's GHG Best Available Control Technology ("BACT") requirements. Upon remand, the D.C. Circuit issued an amended judgment, which, among other things, vacated the PSD and Title V regulations under review in that case to the extent they require a stationary source to obtain a PSD or Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. In October 2016, EPA issued a proposed rule to further revise its PSD and Title

V regulations applicable to GHGs in accordance with these court rulings, including a proposed de minimis level of GHG emissions below which BACT is not required. This rulemaking process is ongoing. Depending on an EPA's final rule, it is possible that any regulatory or permitting obligation that limits emissions of GHGs could extend to smaller stationary sources and require us to incur costs to reduce and monitor emissions of GHGs associated with our operations, and may also adversely affect demand for the oil and natural gas that we produce.

In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule.

In August of 2015, the EPA finalized rules to further reduce GHG emissions, primarily from coal-fired power plants, under its Clean Power Plan ("CPP"). On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the CPP regulations. Following the Executive Order, on April 4, 2017, the EPA announced that it was formally reviewing the CPP. On October 9, 2017, the EPA published a proposed rule to repeal the Clean Power Plan. The comment period on the proposed rule closed on April 26, 2018. On August 21, 2018, EPA proposed the Affordable Clean Energy ("ACE") rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. On July 8, 2019, EPA published the final ACE Rule. The ACE replaces the CPP and provides states with new emission guidelines that will inform their development of standards of performance to reduce carbon dioxide (CO_2) emissions from existing coal-fired power plants. Long-pending legal challenges to the CPP rule filed by states, industry and environmental groups were dismissed as moot by the D.C. Circuit Court of Appeals on September 17, 2019, given the issuance of a final replacement ACE rule.

Congress has, from time to time, considered but not yet passed legislation to reduce emissions of GHGs. In addition, a number of state and regional efforts have emerged 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, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Additional GHG regulation may also result from the December 2015 agreement that the United States reached during the December 2015 United Nations climate change conference in Paris, France (the "Paris Agreement"). Within the Paris Agreement, the United States agreed to reduce its GHG emissions by 26-28% by the year 2025 as compared with 2005 levels, and provide periodic updates on its progress. On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. Although President Trump has the authority to unilaterally withdraw the United States from the Paris Agreement, it is not clear at this time what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement.

On May 30, 2019, Colorado also passed GHG inventory legislation and climate action legislation. House Bill 19-1261 concerns the reduction of greenhouse gas pollution and established statewide greenhouse gas pollution reduction goals. Senate Bill 19-096 concerns the collection of greenhouse gas emissions data to facilitate measures to cost-effectively meet the states GHG emissions reduction goals established in HB 19-1261.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting, emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect our production operations and/or demand for the oil and natural gas we produce. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities.

Water discharges

The Federal Water Pollution Control Act or the Clean Water Act ("CWA") and analogous state laws impose restrictions and controls regarding the discharge of pollutants into certain surface waters of the U.S., including spills and leaks of hydrocarbons and produced water. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control, and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. As properties are acquired, we determine the need for new or updated SPCC plans and, where necessary, will develop or update such plans to implement physical and operation controls, the costs of which are not expected to be material. In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") adopted a new regulatory definition of "waters of the U.S." ("WOTUS"), which governs which waters and wetlands are subject to the CWA. In February 2018, the EPA issued a rule that delays the applicability of the new definition of the waters of the United States until 2020. On August 16, 2018, the U.S. District Court for South Carolina found that the EPA and the Corps failed to comply with the Administrative Procedure Act and struck the 2018 rule that attempted to delay the applicability date of the 2015 rule. Other district courts, however, have issued rulings temporarily enjoining the applicability of the 2015 rule itself. On December 11, 2018, the EPA and the Corps issued a proposed new rule that would differently revise the definition of "waters of the United States" and essentially replace both the 1986 rule and the 2015 rule. According to the agencies, the proposed new rule is "intended to increase CWA program predictability and consistency by increasing clarity as to the scope of 'waters of the United States' federally regulated under the Act." The new WOTUS Rule was published as a final rule ("2019 WOTUS Rule") on October 22, 2019. This new 2019 WOTUS Rule definition of "waters of the United States" will likely be challenged and sought to be enjoined in federal court. One such challenge has been filed by environmental and conservation groups arguing that repeal of the 2015 Rule could not automatically revert back to the 1986 Rule without first proposing reversion and separately soliciting comment thereon. Additionally, in June 2016, the EPA finalized new CWA pretreatment standards that would prevent onshore unconventional oil and natural gas wells from discharging wastewater pollutants to publicly-owned treatment facilities. Regulated entities are required to come into compliance with these pretreatment standards by August 29, 2019.

Endangered Species Act

The federal Endangered Species Act restricts activities that may affect endangered and threatened species or their habitats. A final rule amending how critical habitat and suitable habitat areas are designated was finalized by the U.S. Fish and Wildlife Service in 2016. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We 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, the purpose of which are to protect the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may impact our operations. These changes include among other items: record keeping and reporting, revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry, and requirements for a safety and health management system. In addition, OSHA's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes, requires that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities, and citizens.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an Environmental Assessment to evaluate the potential direct, indirect, and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. The vast majority of our exploration and production activities are not on federal lands. This environmental impact assessment process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects. On January 10, 2020, the Council on Environmental Quality proposed comprehensive amendments to NEPA's implementing regulations to make the NEPA process more efficient, effective, and timely.

Oil Pollution Act

The Oil Pollution Act of 1990 ("OPA") establishes strict liability for owners and operators of facilities that release oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction, or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

Employees

As of December 31, 2019, we had 125 employees, of which 27 full-time employee equivalents were dedicated to our Rocky Mountain Infrastructure, LLC operations. We also utilized the services of numerous independent contractors to perform various field and other services. Our future success will depend partially on our ability to attract, retain, and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Offices

As of December 31, 2019, we leased 63,783 square feet of office space in Denver, Colorado at 410 17th Street where our principal offices are located, and we leased 7,780 square feet near our operations in Weld County, Colorado, where we have a field office and storage facilities. We also own a field office in Evans, Colorado.

Available Information

We are required to file annual, quarterly, and current reports, proxy statements and other information with the SEC. Our filings with the SEC are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "BCEI." Our reports, proxy statements, and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.bonanzacrk.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

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

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to Our Business

Further declines, in oil and, to a lesser extent, natural gas prices, will adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas and natural gas liquids ("NGLs"), heavily influences our revenue, profitability, cash flows, liquidity, access to capital, present value and quality of our reserves, the nature and scale of our operations, and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 71% of our estimated proved reserves as of December 31, 2019 were oil and NGLs, our financial results are more sensitive to movements in oil prices. Since mid-2014, the price of crude oil has significantly declined and has not regained previous highs. As a result, we experienced significant decreases in crude oil revenues and recorded asset impairment charges. A prolonged period of low market prices for oil, natural gas, and NGLs or further declines in the market prices for oil and natural gas, could result in capital expenditures being further reduced and will adversely affect our business, financial condition, and liquidity and our ability to meet obligations, targets, or financial commitments. During the year ended December 31, 2019, the daily NYMEX WTI oil spot price ranged from a high of $66.24 per Bbl to a low of $46.31 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $4.25 per MMBtu to a low of $1.75 per MMBtu. As of February 24, 2020, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $51.33 per Bbl and $1.94 per MMBtu, respectively.

The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- the price and availability of competitors’ supplies of oil and natural gas;
- technological advances affecting energy consumption;
- variability in subsurface reservoir characteristics, particularly in areas with immature development history;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under contracts at market-based prices. Declines in commodity prices may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas, and NGLs that we can produce economically, and reduction in our liquidity and inability to pay our liabilities as they come due;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- significant reductions in future capital programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- reduction to the borrowing base under our Credit Facility (defined below) or limitations in our access to sources of capital, such as equity or debt;
- declines in our stock price;
- reduction in industry demand for crude oil;
- reduction in storage availability for crude oil;
- reduction in pipeline and processing industry demand and capacity for natural gas;
- reduction in the ability of our vendors, suppliers, and customers to continue operations due to the prevailing adverse market conditions; and
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment.

Our production is not fully hedged, and we are exposed to fluctuations in the price of oil and will be affected by continuing and prolonged declines in the price of oil and natural gas.

Oil and natural gas prices are volatile. We hedge a portion of our oil and natural gas production to reduce our exposure to adverse fluctuations in these prices. We have stated limitations as prescribed in our reserve-based revolving credit facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions as lenders (the “Credit Facility”) as to the percentage of our production that can be hedged. The limitations range from 85% to 100% of our projected production from our proved developed properties and 65% to 85% of our projected production from our total proved properties, dependent on the duration of the hedge. Due to the Credit Facility's restrictions and/or management's decision to hedge less than 100% of our projected production, some of our future production will be sold at market prices, exposing us to fluctuations in the price of crude oil and natural gas. Currently, we have approximately 58% of our guided 2020 oil production hedged as oil constituted 85% of our oil and gas sales in 2019. To the extent that the price of oil and natural gas decline below current levels, our results of operations and financial condition would be materially adversely impacted. See the *Derivative Activity* section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

Due to reduced commodity prices and lower operating cash flows we may be unable to maintain adequate liquidity, and our ability to make interest payments in respect of any indebtedness could be adversely affected.

Oil, natural gas, and NGL prices have significantly declined since mid-2014 and have not regained previous highs. We have substantial capital needs in connection with the continued development of our oil and gas assets. We may not have the ability to generate sufficient cash flows from operations, and our Credit Facility's borrowing base may be reduced in the future. Therefore, we may have insufficient liquidity to meet our anticipated working capital, debt service, and other liquidity needs.

Terrorist attacks could have a material adverse effect on our business, financial condition, or results of operations.

Terrorist attacks may significantly affect the energy industry, including our operations and those of our current and potential customers, as well as general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of our reorganization plan and the transactions contemplated thereby and the adoption of fresh-start accounting.

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

In addition, upon emergence from bankruptcy, we adopted fresh-start accounting, as a consequence of which our assets and liabilities were adjusted to fair value and our accumulated deficit was restated to zero. Accordingly, our future financial conditions and results of operations following our emergence are not comparable to the financial condition or results of operations reflected in our historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

The Credit Facility has restrictive covenants that could limit our growth and our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.

The Credit Facility contains restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio and a maximum leverage ratio. In addition, the Credit Facility contains covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- issue preferred stock;
- sell or transfer assets;
- pay dividends on, redeem, or repurchase capital stock;
- repurchase or redeem subordinated debt;
- make certain acquisitions and investments;
- create or incur liens;
- engage in transactions with affiliates;
- enter into agreements that restrict distributions or other payments from restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets; and
- engage in certain other business activities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of the date of this Annual Report on Form 10-K, we are in compliance with all financial and non-financial covenants.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in the Credit Facility. Our ability to comply with the financial ratios and financial condition tests under the Credit Facility may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in commodity prices, our business, or the economy in general, or otherwise conduct necessary corporate activities.

Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under the Credit Facility is redetermined at least semiannually and up to two additional times per year between scheduled determinations upon request of us or lenders holding more than 50% of the aggregate commitments. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors. Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing, or sell significant assets, all of which could have a material adverse effect on our business and financial results.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, lease, explore, develop, or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see *Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves* below. Our cost of drilling, completing, and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors, including, but not limited to, the following, may result in substantial losses, including personal injury or loss of life, penalties, damage or destruction of property and equipment, and curtailments, delays, or cancellations of our scheduled drilling, completion, and infrastructure projects:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- unanticipated environmental liabilities;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as extreme cold temperatures, blizzards, ice storms, tornadoes, floods, and fires;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title problems;
- safety concerns; and
- limitations in the market for oil and natural gas.

Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves and the production possible from our oil and gas wells is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for information about our estimated oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2019, 2018, and 2017.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production, and engineering data. The extent, quality, and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds, and given the current volatility in pricing, such assumptions are difficult to make. Although the reserves information contained herein is reviewed by independent reserves engineers, estimates of oil and natural gas reserves are inherently imprecise, particularly as they relate to state-of-the-art technologies being employed, such as the combination of hydraulic fracturing and horizontal drilling.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and potential impairment charges. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices, and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2019, 2018, and 2017, we based the estimated discounted future net revenues from our proved reserves on the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months (after adjustment for location and quality differentials), without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas and hedging instruments;
- actual cost of development and production activities;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- wellbore productivity realizations above or below type curve forecast models;
- the supply and demand of oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor (the factor required by the SEC) used when calculating discounted future net revenues 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.

As a result of the predominately sustained decrease in prices for oil, natural gas, and NGLs since the fourth quarter of 2014, we have taken write-downs of the carrying value of our properties and may be required to take further write-downs if oil and natural gas prices remain depressed or decline further or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs, or deterioration in our drilling results.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics, and other factors, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Oil, natural gas, and NGL prices have significantly declined since the middle of 2014 and have not regained previous highs. Additionally, given the history of price volatility in the oil and natural gas markets, prices could remain depressed or decline further or other events may arise that would require us to record further impairments of the book values associated with oil and natural gas properties. Accordingly, we may incur significant impairment charges in the future which could have a material adverse effect on our results of operations and could reduce our earnings and stockholders’ equity for the periods in which such charges are taken.

We intend to pursue the further development of our properties in the Wattenberg Field through horizontal drilling and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.

Horizontal drilling is generally more complex and more expensive on a per well basis than vertical drilling. As a result, there is greater risk associated with a horizontal well program. Risks associated with our horizontal drilling program include, but are not limited to, the following, any of which could materially and adversely impact the success of our horizontal drilling program and, thus, our cash flows and results of operations:

- successfully drilling and maintaining the wellbore to planned total depth;
- landing our wellbore in the desired hydrocarbon reservoir;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired hydrocarbon reservoir while drilling horizontally through the formation;
- running our casing through the entire length of the wellbore;
- running tools and other equipment consistently through the horizontal wellbore;
- fracture stimulating the planned number of stages;
- preventing downhole communications with other wells;
- successfully cleaning out the wellbore after completion of the final fracture stimulation stage; and
- designing and maintaining efficient forms of artificial lift throughout the life of the well.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, limited takeaway capacity, or depressed natural gas and oil prices, the return on our investment in these areas may not be as attractive as anticipated. Further, as a result of any of these developments, we could incur material impairments of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Our ability to produce natural gas and oil economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of oil and natural gas requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water (including during times of droughts), or to dispose of or recycle the water used in our operations, could adversely impact our operations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil and natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our operations and financial condition.

The unavailability or high cost of additional drilling rigs, pressure pumping fleets, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, pressure pumping fleets, equipment, supplies, personnel, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition, or results of operations and may lead to reduced liquidity and the inability to pay our liabilities as they come due.

Our exploration, development, and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.

Our exploration, development, and exploitation activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production, and acquisition of oil and natural gas reserves. At this time, we intend to finance future capital expenditures primarily through cash flows provided by operating activities and borrowings under the Credit Facility. Declines in commodity prices coupled with our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities or debt securities or the strategic sale of assets. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures, and acquisitions. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under the Credit Facility would be reduced. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of oil and natural gas we are able to produce from new and existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under the Credit Facility decreases or if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations. If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by operations or cash available under the Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our undeveloped leases and a decline in our oil and natural gas reserves, and an adverse effect on our business, financial condition, and results of operations.

Increased costs of capital could adversely affect our business.

Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, impacting our ability to finance our operations. Our business and operating results can be harmed by factors such as the terms and cost of capital, increases in interest rates, or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling, render us unable to replace reserves and production, and place us at a competitive disadvantage.

Concentration of our operations in one core area may increase our risk of production loss.

Our assets and operations are currently concentrated in one core area: the Wattenberg Field in Colorado. The core area currently provides 100% of our current sales volumes and development projects.

Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas, and NGLs produced from wells in the area, accidents or natural disasters, restrictive governmental regulations, curtailment of production, interruption in the availability of gathering, processing, or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. Similarly, the concentration of our assets within a single producing formation exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to the formation. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, we are subject to increasing competition for drilling rigs, pressure pumping fleets, oilfield equipment, services, supplies, and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We do not maintain business interruption (loss of production) insurance for our oil and gas producing properties. Loss of production or limited access to reserves in our core operating area could have a significant negative impact on our cash flows and profitability.

As a Colorado-only oil and gas operator, we face disproportionate risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Further efforts could result in the following:

- delay or denial of drilling permits;
- revocation or modification of drilling permits or other necessary authorizations;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of production, gathering, or processing facilities;
- mandatory and lengthy distances between drilling locations and buildings and/or bodies of water or other protected areas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about us or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Specifically in Colorado, anti-development activity has both increased and become more effective in recent years. On April 16, 2019, new legislation became effective in Colorado, which substantially changes the state’s regulation of oil and gas exploration and production activities, and applies immediately to all pending permit applications. The new law changes the COGCC's mission from “fostering” responsible and balanced development to “regulating” public health and the environment. The required composition of the COGCC was also changed to remove two seats for oil and gas industry experts and add experts on wildlife/environmental protection and public health. The state’s statutory pooling provisions were changed by the new law to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required.

Among the most significant changes under the legislation was the provision of local government control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions.

The legislation mandates the COGCC rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. Pending the completion of this initial rulemaking, the COGCC may delay acting on selected permit applications.

Further, on October 17, 2019, the CDPHE published a health risk assessment for oil & gas operations in Colorado. The assessment is based on modeling done with certain historic emissions data and found the possibility of negative short-term health impacts at distances out to 2,000 feet from facilities engaged in pre-production operations (i.e., drilling, completion, and flowback) under worst-case conditions. In response to the assessment, the COGCC announced that it will more rigorously scrutinize permit applications for wells within 2000 feet of a building unit. The COGCC also announced that it will collect new data from oil & gas wells, compare the data to the assessment published by the CDPHE, and use the data to inform the COGCC's new regulations and rulemakings.

Permitting delays that occur while the COGCC rulemaking process proceeds, as well as delays that may result from the new COGCC rules and regulations themselves, could substantially curtail the Company's near-term pace of new oil and gas development. We have already observed a marked decline in the pace at which permit applications are being granted, and if this trend continues, it could have a material adverse effect on our business, financial condition, and results of operations.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds, and nitrogen oxides associated with certain oil and gas facilities. The AQCC may also adopt more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, installation of continuous emission monitoring equipment at certain oil and gas facilities, and reduced emissions from pneumatic devices. The legislation also grants the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling, and completion.

Rules adopted by the COGCC and AQCC pursuant to the new legislation may significantly increase the Company's operating costs, and have a material adverse effect on our business, financial condition, and results of operations.

Additionally, anti-development activists succeeded in adding a measure to the November 6, 2018 ballot in Colorado, which sought to require a minimum 2,500 foot setback from occupied structures and vulnerable areas for all new oil and gas development on non-federal land. While this initiative was ultimately unsuccessful, had it been successful, it may have resulted in dramatically reducing the area of future oil and gas development in Colorado. Similar ballot measures have been submitted for the 2020 election by anti-development activist groups. Such anti-development efforts are likely to continue in the future, which could result in dramatically reducing the area of future oil and gas development in Colorado or outright banning oil and gas development in Colorado. These efforts could have a material adverse effect on our business, financial condition, and results of operations.

State law requiring that we own or control more than 45% of the working or mineral interest in order to statutorily pool our applicable interest may make it much more difficult for us to develop such interests, which could have a material adverse effect on our business, financial condition, and results of operations.

In many cases, we do not own more than 45% working interest or mineral interest in a prospective area of development, which is now required to statutorily pool our applicable working or mineral interests. In such cases, unless we can obtain the consent of more than 45% of all applicable working or mineral interest owners (who can be located through reasonable diligence) to pursue statutory pooling, or achieve a voluntary pooling agreement with 100% of the applicable interest owners, we may be prohibited from developing the resources in that area.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We do not operate all of the properties in which we have an interest. For example, we will not operate the majority of our assets in the southern French Lake area. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures, or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants, and the use of technology. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, revenues, production, and related matters.

We are dependent on third-party pipeline, trucking, and rail systems to transport our oil production and gathering and processing systems to deliver our natural gas production. These systems have limited capacity and at times have experienced service disruptions. Curtailments, disruptions, or lack of availability in these systems interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production depends in part on the availability, proximity, and capacity of gathering, processing, pipeline, trucking, and rail systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, maintenance, weather, field labor issues, or disruptions in service. Curtailments and disruptions in these systems may last from a few days to several months. Any significant curtailment in gathering, processing, or pipeline system capacity, significant delay in the construction of necessary facilities, or lack of availability of transport, would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations, and the expected results of our development program.

The concentrated nature of our RMI system may increase the risk that we suffer lengthy interruptions in our production.

Through our Rocky Mountain Infrastructure, LLC (“RMI”) subsidiary, we have consolidated and interconnected our gathering, treating, and production facilities. This approach includes, for example, greater use of central processing facilities and central compression stations than some other operators in the Wattenberg Field. The concentrated nature of the RMI system, by itself, could increase the length and magnitude of a production interruption caused by operational problems located in otherwise localized portions of the system. Such interruptions could materially and adversely affect our ability to meet our public guidance, our financial condition, and our results of operations.

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

Approximately 55% of our total proved reserves were classified as proved undeveloped as of December 31, 2019. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate or that may be available to us. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development, and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

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

Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as spills, uncontrollable flows of oil, natural gas, brine, well fluids, natural gas, hazardous air pollutants, or other pollution into the environment, including soil, surface water, groundwater, and shoreline contamination;
- releases of natural gas and hazardous air pollutants or other substances into the atmosphere (including releases at our oil and gas facilities);
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in natural gas we produce;
- abnormally pressured formations resulting in well blowouts, fires, or explosions;
- mechanical difficulties, such as stuck down-hole tools or casing collapse;
- cratering (catastrophic failure);
- downhole communication leading to migration of contaminants;
- personal injuries and death; and
- natural disasters.

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

- injury or loss of life;
- damage to and destruction of property, natural resources, and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

The presence of H_2S, a toxic, flammable, and colorless gas, is a common risk in the oil and gas industry and may be present in small amounts for brief periods from time to time at our well and facility locations. In addition, our operations in Colorado are susceptible to damage from natural disasters, such as flooding, wildfires, tornadoes, and other natural phenomena and weather conditions, including extreme temperatures, which involve increased risks of personal injury, property damage, and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation, and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

As is customary in the oil and gas industry, we maintain insurance against some, but not all, of these potential risks and losses. Although we believe the coverage and amounts of insurance that we carry are consistent with industry practice, we do not have insurance protection against all risks that we face, because we choose not to insure certain risks, insurance is not available at a level that balances the costs of insurance and our desired rates of return, or actual losses exceed coverage limits. Insurance costs will likely continue to increase, which could result in our determination to decrease coverage and retain more risk to mitigate those cost increases. In addition, pollution and environmental risks generally are not fully insurable. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition may be materially adversely affected.

Because hydraulic fracturing activities are integral to our operations, they are covered by our insurance against claims made for bodily injury, property damage, and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. We also do not have coverage for gradual, long-term pollution events.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean-up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional evaluation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. Prior to drilling, the use of 2-D and 3-D seismic technologies, various other technologies, and the study of producing fields in the same area will not enable us to know conclusively 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. In addition, the use of 2-D and 3-D seismic data and other technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures which may result in a reduction in our returns or increase our losses. 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. If we drill any dry holes in our current and future drilling locations, our profitability and the value of our properties will likely be reduced. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing, and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling locations are scheduled to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of development. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including uncertainty in the level of reserves, the availability of capital to us and other participants, seasonal conditions, regulatory approvals, oil, natural gas and NGL prices, availability of permits, costs, and well performance. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible categories any proved undeveloped reserves that are not developed within this five-year time frame. These limitations may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The terms of our oil and gas leases often stipulate that the lease will terminate if not held by production, rentals, or some form of an extension payment to extend the term of the lease. As of December 31, 2019, if production in paying quantities is not established on units containing leases not held by production during the next year, then approximately 2,669 net acres will expire in 2020, approximately 1,880 net acres will expire in 2021, and approximately 1,448 net acres will expire in 2022 and thereafter. While some expiring leases may contain predetermined extension payments, other expiring leases will require us to negotiate new leases at the time of lease expiration. It is possible that market conditions at the time of negotiation could require us to agree to new leases on less favorable terms to us than the terms of the expired leases or cause us to lose the leases entirely. If our leases expire, we will lose our right to develop the related properties.

We may incur losses as a result of title deficiencies.

The existence of a title deficiency can diminish the value of an acquired leasehold interest and can adversely affect our results of operations and financial condition. Title insurance covering mineral leasehold interests is not generally available. As is industry standard, we may rely upon a land professional's careful examination of public records prior to purchasing or leasing a mineral interest. Once a mineral or leasehold interest has been acquired, we typically defer the expense of obtaining further title verification by a practicing title attorney until approval to drill a well that includes the acquired mineral interest is required. We perform the necessary curative work to correct deficiencies in the marketability of the title, and we have compliance and control measures to ensure any associated business risk is approved by the appropriate Company authority. In cases involving more serious title deficiencies, all or part of a mineral or leasehold interest may be determined to be invalid or unleased, and, as a result, the target area may be deemed to be undrillable until owners can be contacted and curative measures performed to adequately perfect title. In other cases, title deficiencies may result in our failure to have paid royalty owners correctly. Certain title deficiencies may also result in litigation to quiet the title and effectively agree or render a decision upon title ownership.

We are subject to health, safety, and environmental laws and regulations that may expose us to significant costs and liabilities.

We are subject to stringent and complex federal, state, and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment, and the protection of the environment. These laws and regulations may impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities, and concentration of materials that may be released into the environment; limitations or prohibitions of drilling or completion activities; the application of specific health and safety criteria to protect the public or workers; and the responsibility for cleaning up pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; delays in granting permits; or even the cancellation of leases.

There is an inherent risk of incurring significant environmental costs and liabilities in our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions into air and water, the underground injection or other disposal of our wastes, the use and disposition of hydraulic fracturing fluids, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable for the full cost of removing or remediating contamination, regardless of whether we were at fault, and even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws then in effect. In addition, accidental spills or releases on or off our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the owners or operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal or otherwise come to be located, and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations, or obtain damages for any related personal injury, or damage and property damage, and certain trustees may seek natural resource damages. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that historic contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position, or financial condition. We may not be able to recover some or any of these costs from insurance.

Evolving environmental legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.

We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Governmental authorities frequently add to those requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing regulatory attention. For example, the COGCC has announced that during 2020 it may revise its regulations on a range of topics including development approvals, cumulative impacts, asset transfers, pollution standards, flaring restrictions, spill reporting, and cleanup responsibility. And legislation passed in 2019 requires the COGCC to assess and potentially revise its financial assurance requirements for oil and gas development. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

Some activists have attempted to link hydraulic fracturing to various environmental problems, including potential adverse effects to drinking water supplies, migration of methane and other hydrocarbons into groundwater, increased seismic activity, and human health effects. The federal government has periodically studied the environmental risks associated with hydraulic fracturing and evaluated whether to adopt, and in some cases have adopted, additional regulatory requirements.

In some instances certain state and local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. Some counties in Colorado, for instance, have amended their land use regulations to impose new requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same objective. Under current Colorado law, local governments can regulate both facility siting and the surface impacts associated with oil and gas development. In addition, voters in Colorado have proposed or advanced ballot initiatives restricting or banning oil and gas development in Colorado. Because our operations and reserves are solely located in Colorado, the risks we face with respect to such ballot initiatives are greater than other companies with more geographically diverse operations.

The adoption of future federal, state, or local laws or implementing regulations imposing new environmental and financial assurance obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance operations, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material adverse impact on our cash flows and results of operations.

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

There is a growing belief that human-caused (anthropogenic) emissions of greenhouse gases GHGs may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and the demand for and consumption of our products (due to potential changes in both costs and weather patterns).

The EPA also adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations. Information in such reporting may form the basis for further GHG regulation. Further, the EPA has continued with its comprehensive strategy for further reducing methane emissions from oil and gas operations, with a final rule being issued in May 2016 as part of “Quad O” discussed above. The EPA’s GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In the meantime, many states already have taken such measures, which have included renewable energy standards, development of GHG emission inventories or cap and trade programs. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities.

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

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend heavily on our financial resources and ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas, and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical, and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for, and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand unsuccessful drilling attempts and sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our business.

A negative shift in investor sentiment of the oil and gas industry could have adverse effects on our ability to raise debt and equity capital and on our operations.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Additionally, negative public perception regarding us and/or our industry may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business. Recently, activists concerned about the potential effects of climate change have directed their attention towards 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 energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

If we fail to retain our existing senior management or technical personnel or attract qualified new personnel, such failure could adversely affect our operations. The volatility in commodity prices and business performance may affect our ability to retain senior management, and the loss of these key employees may affect our business, financial condition, and results of operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management, technical personnel, or any of the vice presidents of the Company, could have a material adverse effect on our operations or strategy. The volatility in commodity prices and our business performance may affect our ability to incentivize and retain senior management or key employees. Competition for experienced senior management, technical, and other professional personnel remains strong.

If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have, and may in the future enter into additional, derivative arrangements for a portion of our oil and natural gas production, including swaps, collars, and puts. We have not in the past designated any of our derivative instruments as hedges for accounting purposes and have recorded all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements. Further, our Credit Facility provides for certain limitations to the extent of our hedging, which may expose us to unfavorable fluctuations in the prices of oil and natural gas.

We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.

Our principal exposures to credit risk are through receivables resulting from commodity derivatives instruments, joint interest and other receivables of $38.1 million at December 31, 2019, and the sale of our oil, natural gas, and NGLs production of $43.7 million in receivables at December 31, 2019, which we market to energy marketing companies, refineries, and affiliates.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our oil, natural gas, and NGLs receivables with significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2019, sales to NGL Crude Logistics, LLC comprised 82% of our total sales. Beginning in 2017 and continuing for seven years, we have contracted to sell up to 16,000 barrels per day of our crude oil produced in the Wattenberg Field to NGL Crude Logistics, LLC.

We are exposed to credit risk in the event of default of our counterparty, principally with respect to hedging agreements, but also with respect to insurance contracts and bank lending commitments. We do not require most of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with our business.

The Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative as a result of the Dodd-Frank Act and regulations, our results of operations may be more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

We may be involved in legal cases that may result in substantial liabilities.

Like many oil and gas companies, we are from time to time involved in various legal and other cases, such as title, royalty or contractual disputes, regulatory compliance matters, and personal injury or property damage matters, in the ordinary course of our business. Such legal cases are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such cases could have an adverse impact on us because of legal costs, diversion of management and other personnel, and other factors. In addition, it is possible that a resolution of one or more such cases could result in liability, penalties, or sanctions, as well as judgments, consent decrees, or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results, and financial condition. Accruals for such liability, penalties, or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other cases could change from one period to the next, and such changes could be material.

In February 2019, the Company was sent a notice of intent to sue (“NOI”) letter by WildEarth Guardians (“WEG”), an environmental non-governmental organization, alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The Company is one of seven operators in the Wattenberg Field to receive such an NOI letter from WEG, and these letters appear to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes.

In May 2019, WEG filed a lawsuit against the Company and the other six operators who received the NOI, alleging claims consistent with those contained in the NOI letters. Because the allegations made in the lawsuit are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit, but the Company will vigorously defend against such allegations and will coordinate as much as possible with state and federal permitting authorities to maintain the validity of its current and future air permits for such facilities.

We are subject to federal, state, and local taxes and may become subject to new taxes, and certain federal income tax deductions and state income tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced as a result of future legislation.

The federal, state, and local governments in the areas in which we operate (i) impose taxes on the oil and natural gas products we sell, and (ii) for many of our wells, impose sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

There have been proposals for legislative changes that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such changes in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations, and cash flow.

In Colorado, there may be proposals for legislative changes that, if enacted into law, could substantially increase our severance tax and ad valorem tax effective rates. Such changes may include, but are not limited to, (i) the reduction or elimination of the credit against severance tax based on the property tax we pay; (ii) the reduction or elimination of certain exemptions impacting severance tax liability; and (iii) increased severance tax rates. Any such changes to Colorado’s ad valorem and severance tax laws could negatively affect our financial condition, results of operations, and cash flow.

Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition, results of operations, and cash flow.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption, or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations, and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. Our technologies, systems, networks, and those of our vendors, suppliers, and other business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, weaknesses in the cyber security of our vendors, suppliers, and other business partners could facilitate an attack on our technologies, systems, and networks. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Given the politically sensitive nature of hydraulic fracturing and the controversy generated by its opponents, our technologies, systems, and networks may be of particular interest to certain groups with political agendas, which may seek to launch cyber-attacks as a method of promoting their message. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient.

We depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business parties, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The technologies needed to conduct our oil and gas exploration and development activities make certain information the target of theft or misappropriation.

Although to date we have not experienced any material losses relating to cyber-attacks, we may suffer such losses in the future.

Risks Relating to our Common Stock

We do not intend to pay, and are subject to certain restrictions on our ability to pay, dividends on our common stock, and consequently, our stockholders' likely only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our Credit Facility places certain restrictions on our ability to pay dividends. Consequently, our stockholders' only likely opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the stockholders sell their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholders paid.

We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.

The trading price of shares of our common stock has fluctuated widely and in the future may be subject to similar fluctuations. As an example, during the 2019 calendar year, the sales price of our common stock ranged from a low of $16.60 per share to a high of $26.75 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of oil, natural gas, and NGL prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition and liquidity, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil, natural gas, and NGL prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the New York Stock Exchange, we cannot assure you that an active public market will continue for our common stock or that we will be able to continue to meet the listing requirements of the NYSE. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests.

Our certificate of incorporation authorizes our Board of Directors (the "Board") to issue preferred stock without stockholder approval. If our Board elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- advance notice provisions for stockholder proposals and nominations for elections to the Board to be acted upon at meetings of stockholders; and
- limitations on the ability of our stockholders to call special meetings or act by written consent.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

The information required by Item 2. is contained in Item 1. *Business* and is incorporated herein by reference.

Item 3. *Legal Proceedings.*

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health, and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this filing, there are no material pending or overtly threatened legal actions against us of which we are aware, except as set forth below.

In February 2019, the Company was sent an NOI letter by WEG, an environmental non-governmental organization, alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The Company is one of seven operators in the Wattenberg Field to receive such an NOI letter from WEG, and these letters appear to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes.

On May 3, 2019, WEG filed a lawsuit against the Company and the other six operators who received the NOI, alleging claims consistent with those contained in the NOI letters. Because the allegations made in the lawsuit are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit, but the Company will vigorously defend against such allegations, and will coordinate as much as possible with state and federal permitting authorities to maintain the validity of its current and future air permits for such facilities.

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.*

Market for Registrant's Common Equity. Our common stock is listed on the NYSE under the symbol "BCEI".

Holders. As of February 24, 2020, there were approximately 33 registered holders of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our Credit Facility restrict the payment of cash dividends on our common stock, as discussed further in *Part II, Item 7, Liquidity and Capital*

Resources. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2019.

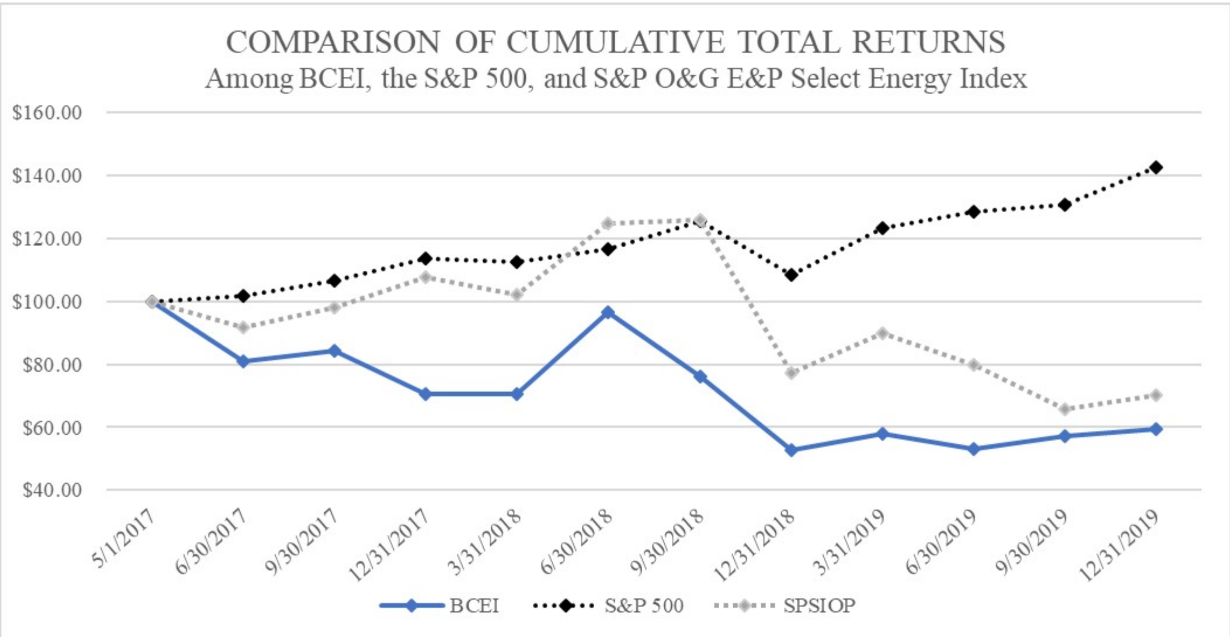
	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Be Purchased Under Plans or Programs
October 1, 2019 - October 31, 2019	158	$ 20.00	—	—
November 1, 2019 - November 30, 2019	1,353	$ 19.07	—	—
December 1, 2019 - December 31, 2019	2,250	$ 19.53	—	—
Total	3,761	$ 19.53	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, nor do we have a publicly announced plan or program to repurchase shares of our common stock.

Sale of Unregistered Securities. We had no sales of unregistered securities during the year ended December 31, 2019.

Stock Performance Graph. The following performance graph shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), or otherwise subject to liabilities under that section and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

The following graph compares the cumulative total stockholder return for the Company’s common stock, the Standard and Poor’s 500 Stock Index (the “S&P 500 Index”) and the Standard and Poor’s 500 Oil & Gas Exploration & Production Index (“S&P O&G E&P Index”). The measurement points in the graph below are May 1, 2017 (the first trading day of our common stock on the NYSE upon emergence) and each fiscal quarter thereafter through December 31, 2019. The graph assumes that $100 was invested on May 1, 2017 in each of the common stock of the Company, the S&P 500 Index and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.



Item 6. *Selected Financial Data.*

The selected historical financial data should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* below and financial statements and the notes to those financial statements in Part I, Item 8 of this Annual Report on Form 10-K.

The following tables set forth selected historical financial data of the Company for the periods indicated (in thousands, except per share amounts).

	Successor			Predecessor		
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Statement of Operations Data:						
Total operating net revenues	$ 313,220	$ 276,657	$ 123,535	$ 68,589	$ 195,295	$ 292,679
Net income (loss)	67,067	168,186	(5,020)	2,660	(198,950)	(745,547)
Basic net income (loss) per common share	$ 3.25	$ 8.20	$ (0.25)	$ 0.05	$ (4.04)	$ (15.57)
Basic weighted-average common shares outstanding	20,612	20,507	20,427	49,559	49,268	47,874
Diluted net income (loss) per common share	$ 3.24	$ 8.16	$ (0.25)	$ 0.05	$ (4.04)	$ (15.57)
Diluted weighted-average common shares outstanding	20,681	20,603	20,427	50,971	49,268	47,874
Selected Cash Flow Data:						
Net cash (used for) provided by operating activities	$ 224,647	$ 116,598	$ 27,574	$ (19,884)	$ 14,563	$ 226,023
Net cash used in investing activities	(255,158)	(164,376)	(82,641)	(6,022)	(67,460)	(452,573)
Net cash (used for) provided by financing activities	$ 28,604	$ 47,998	$ (2,398)	$ 15,406	$ 112,062	$ 245,307
Sales Volumes:						
Oil (MBbls)(1)	5,135.9	3,840.8	2,012.7	1,068.5	4,309.9	6,072.3
Natural gas (MMcf)(2)	11,966.8	8,591.2	5,938.0	3,336.1	12,231.3	14,551.1
Natural gas liquids (MBbls)	1,431.1	1,141.2	762.4	449.0	1,587.0	1,821.9
Average Sales Price (before derivatives):						
Oil (MBbls)(1)	$ 51.89	$ 59.38	$ 47.18	$ 48.29	$ 35.31	$ 40.95
Natural gas (MMcf)(2)	$ 2.06	$ 2.45	$ 2.29	$ 2.57	$ 1.76	$ 1.77
Natural gas liquids (MBbls)	$ 11.22	$ 22.46	$ 18.38	$ 17.52	$ 12.39	$ 9.49
Average Sales Price (after derivatives):						
Oil (MBbls)(1)	$ 52.12	$ 54.77	$ 46.44	$ 48.29	$ 39.57	$ 62.07
Natural gas (MMcf)(2)	$ 2.10	$ 2.39	$ 2.29	$ 2.57	$ 1.76	$ 1.95
Natural gas liquids (MBbls)	$ 11.22	$ 22.46	$ 18.38	$ 17.52	$ 12.39	$ 9.49
Expense per BOE:						
Lease operating expense and gas plant and midstream operating expense	$ 4.35	$ 7.11	$ 9.09	$ 8.04	$ 7.12	$ 7.40
Severance and ad valorem taxes	$ 2.99	$ 2.96	$ 2.55	$ 2.73	$ 1.93	$ 1.81
Depreciation, depletion, and amortization	$ 8.93	$ 6.53	$ 5.66	$ 13.54	$ 14.01	$ 23.73
General and administrative	$ 4.63	$ 6.62	$ 11.34	$ 7.28	$ 9.71	$ 6.81

(1) Crude oil sales excludes $2.4 million, $0.6 million, $0.2 million, $0.1 million, $0.5 million, and $0.2 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, the 2017 Successor Period, the 2017 Predecessor Period, and the predecessor years ended December 31, 2016 and 2015, respectively.

(2) Natural gas sales excludes $3.7 million, $1.3 million, $0.8 million, $0.4 million, $1.5 million, and $0.8 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, the 2017 Successor Period, the 2017 Predecessor Period, and the predecessor years ended December 31, 2016 and 2015, respectively.

The following table sets forth selected historical financial data of the Company as of the period indicated (in thousands).

	Successor			Predecessor	
	As of December 31,			As of December 31,	
	2019	2018	2017	2016	2015
Balance Sheet Data:					
Cash and cash equivalents	$ 11,008	$ 12,916	$ 12,711	$ 80,565	$ 21,341
Property and equipment, net (excludes assets held for sale)	1,053,575	917,974	774,082	1,018,968	922,344
Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization	—	—	—	—	214,922
Total assets	1,206,318	1,061,534	830,371	1,134,478	1,259,641
Debt					
Credit Facility	80,000	50,000	—	—	—
Prior Credit Facility	—	—	—	191,667	79,000
Senior Notes, net of unamortized premium and deferred financing costs	—	—	—	793,698	792,666
Total stockholders’ equity	$ 936,690	$ 863,913	$ 688,334	$ 19,061	$ 209,407
Estimated Proved Reserves:					
Oil (MMBbls)	64.4	64.4	52.9	50.1	57.4
Natural gas (Bcf)	212.2	165.0	157.7	138.0	144.2
Natural gas liquids (MMBbls)	22.2	24.9	22.8	17.5	19.9
Total proved reserves (MMBoe)	121.9	116.8	102.0	90.7	101.3

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

The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Such forward-looking statements should be read in conjunction with our disclosures under "Item 1A. Risk Factors" of this Form 10-K.

This section of this Form 10-K generally discusses 2019 and 2018 results and year-to-year comparisons between 2019 and 2018. Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of Bonanza Creek's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and are incorporated herein by reference.

Executive Summary

We are an independent Denver-based exploration and production company focused on the acquisition, development, and extraction of oil and associated liquids-rich natural gas in the United States. Our oil and liquids-weighted assets and operations are concentrated in the rural portions of the Wattenberg Field in Weld County, Colorado. Our development and extraction activities are primarily directed at the horizontal development of the Niobrara and Codell formations in the DJ Basin. We intend to continue the development of our reserves and increase production on our multi-year inventory of identified potential drilling locations and through potential mergers and acquisitions that meet our strategic and financial objectives. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and gas resources. We seek to balance production growth with maintaining a conservative balance sheet. Key aspects of our strategy include multi-well pad development across our leasehold, enhanced completions through continuous design evaluation, utilization of scaled infrastructure, continuous safety improvement, strict adherence to health and safety regulations, and environmental stewardship.

Financial and Operating Results

Our 2019 financial and operational results include:

- Lease operating expense decreased by $9.6 million or $2.48 per Boe for the year ended December 31, 2019 when compared to the same period during 2018;
- General and administrative expense per Boe decreased by 30% for the year ended December 31, 2019 when compared to the same period during 2018;
- Crude oil equivalent sales volumes increased 33% for the year ended December 31, 2019 when compared to the same period during 2018;
- Total liquidity of $281.0 million at December 31, 2019, consisting of cash on hand plus funds available under our Credit Facility. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Cash flows provided by operating activities for the year ended December 31, 2019 was $224.6 million, as compared to cash flows provided by operating activities of $116.6 million during the year ended December 31, 2018. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Proved reserves of 121.9 MMBoe as of December 31, 2019 increased 4% when compared to proved reserves as of December 31, 2018;
- Incurred capital expenditures, inclusive of accruals, of $222.2 million during the year ended December 31, 2019, which was below guidance; and
- Operations of the Company's new oil gathering line to Riverside Terminal commenced in July, resulting in a corresponding $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line.

When considering these comparisons of financial and operational results, note that the results for the year ended December 31, 2018 reflected the partial inclusion of our Mid-Continent assets that were sold on August 6, 2018.

Rocky Mountain Infrastructure

The Company's gathering, treating, and production facilities, maintained under its RMI subsidiary, provide many operational benefits to the Company and provides cost economies of a centralized system. The RMI system reduces gathering system pressures at the wellhead, improving hydrocarbon recovery. Additionally, with eleven interconnects to four different natural gas processors, RMI helps ensure that the Company's production is not constrained by any single midstream service provider. Furthermore, the system reduces facility site footprints, leading to more cost-efficient operations and reduced surface disturbance. The net book value of the Company's RMI assets was $147.8 million as of December 31, 2019.

2020 Capital Budget

The Company's 2020 capital budget of $215 million to $235 million assumes the continuation of a one-rig operated program in the Company's legacy acreage and the startup of a one-rig non-operated program in the Company's French Lake area in late 2020. The Company's 2020 capital expenditures guidance includes $20 million to $25 million for non-operated capital, which includes approximately $10 million to $15 million for French Lake. The budget includes the drilling of 61 gross wells, completion of 45 gross wells, and turning to sales of 62 gross wells. Actual capital expenditures could vary significantly based on, among other things, changes in the operator’s development pace in French Lake, market conditions, commodity prices, drilling and completion costs, well results, and changes in the borrowing base under our Credit Facility.

Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto contained in Part II, Item 8 of this Annual Report on Form 10-K. Comparative results of operations for the period indicated are discussed below.

The following table summarizes our product revenues, sales volumes, and average sales prices for the periods indicated:

	Year Ended December 31, 2019	Year Ended December 31, 2018	Change	Percent Change
Revenues (in thousands):				
Crude oil sales[1]	$ 266,480	$ 228,075	$ 38,405	17 %
Natural gas sales[2]	24,624	21,022	3,602	17 %
Natural gas liquids sales	16,060	25,627	(9,567)	(37)%
Product revenue	$ 307,164	$ 274,724	$ 32,440	12 %
Sales Volumes:				
Crude oil (MBbls)[4]	5,135.9	3,840.8	1,295.1	34 %
Natural gas (MMcf)[5]	11,966.8	8,591.2	3,375.6	39 %
Natural gas liquids (MBbls)[6]	1,431.1	1,141.2	289.9	25 %
Crude oil equivalent (MBoe)[3]	8,561.5	6,413.8	2,147.7	33 %
Average Sales Prices (before derivatives)[7]:				
Crude oil (per Bbl)	$ 51.89	$ 59.38	$ (7.49)	(13)%
Natural gas (per Mcf)	$ 2.06	$ 2.45	$ (0.39)	(16)%
Natural gas liquids (per Bbl)	$ 11.22	$ 22.46	$ (11.24)	(50)%
Crude oil equivalent (per Boe)[3]	$ 35.88	$ 42.83	$ (6.95)	(16)%
Average Sales Prices (after derivatives)[7]:				
Crude oil (per Bbl)	$ 52.12	$ 54.77	$ (2.65)	(5)%
Natural gas (per Mcf)	$ 2.10	$ 2.39	$ (0.29)	(12)%
Natural gas liquids (per Bbl)	$ 11.22	$ 22.46	$ (11.24)	(50)%
Crude oil equivalent (per Boe)[3]	$ 36.07	$ 40.00	$ (3.93)	(10)%

(1) Crude oil sales excludes $2.4 million and $0.6 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, respectively.
(2) Natural gas sales excludes $3.7 million and $1.3 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2019 and 2018, respectively.
(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.
(4) Crude oil sales volumes includes 340.6 MBbls of sales volumes from the Mid-Continent region for the year ended December 31, 2018. The Mid-Continent region assets were sold August 6, 2018, and therefore, no sales volumes were associated with the Mid-Continent region during the year ended December 31, 2019.
(5) Natural gas sales volumes includes 1,182.8 MMcf of sales volumes from the Mid-Continent region for the year ended December 31, 2018. The Mid-Continent region assets were sold August 6, 2018, and therefore, no sales volumes were associated with the Mid-Continent region during the year ended December 31, 2019.
(6) Natural gas liquids sales volumes includes 92.8 MBbls of sales volumes from the Mid-Continent region for the year ended December 31, 2018. The Mid-Continent region assets were sold August 6, 2018, and therefore, no sales volumes were associated with the Mid-Continent region during the year ended December 31, 2019.
(7) Derivatives economically hedge the price we receive for crude oil and natural gas. For the year ended December 31, 2019, the derivative cash settlement gain for oil and natural gas was $1.2 million and $0.5 million, respectively. For the year ended December 31, 2018, the derivative cash settlement loss for oil and natural gas was $17.7 million and $0.5 million, respectively. Please refer to *Part II, Item 8, Note 12 - Derivatives* for additional disclosures.

Product revenues increased by 12% to $307.2 million for the year ended December 31, 2019 compared to $274.7 million for the year ended December 31, 2018 largely due to a 33% increase in sales volumes partially offset by a $6.95 or 16% decrease in oil equivalent pricing excluding the impact of derivatives. The increase in sales volumes is due to turning 45 gross wells to sales during the twelve month period ending December 31, 2019.

The following table summarizes our operating expenses for the periods indicated (in thousands, except per Boe amounts):

	Year Ended December 31, 2019	Year Ended December 31, 2018	Change	Percent Change
Operating Expenses:				
Lease operating expense	$ 25,249	$ 34,825	$ (9,576)	(27)%
Gas plant and midstream operating expense	12,014	10,788	1,226	11 %
Gathering, transportation, and processing	16,682	9,732	6,950	71 %
Severance and ad valorem taxes	25,598	18,999	6,599	35 %
Exploration	797	291	506	174 %
Depreciation, depletion and amortization	76,453	41,883	34,570	83 %
Abandonment and impairment of unproved properties	11,201	5,271	5,930	113 %
Unused commitments	—	21	(21)	(100)%
General and administrative expense	39,668	42,453	(2,785)	(7)%
Operating expenses	$ 207,662	$ 164,263	$ 43,399	26 %
Selected Costs ($ per Boe):				
Lease operating expense	$ 2.95	$ 5.43	$ (2.48)	(46)%
Gas plant and midstream operating expense	1.40	1.68	(0.28)	(17)%
Gathering, transportation, and processing	1.95	1.52	0.43	28 %
Severance and ad valorem taxes	2.99	2.96	0.03	1 %
Exploration	0.09	0.05	0.04	80 %
Depreciation, depletion and amortization	8.93	6.53	2.40	37 %
Abandonment and impairment of unproved properties	1.31	0.82	0.49	60 %
General and administrative expense	4.63	6.62	(1.99)	(30)%
Operating expenses	$ 24.25	$ 25.61	$ (1.36)	(5)%
Operating expenses, excluding impairments and abandonments and unused commitments	$ 22.94	$ 24.79	$ (1.85)	(7)%

Lease operating expense. Our lease operating expense decreased $9.6 million or 27%, to $25.2 million for the year ended December 31, 2019 from the year ended December 31, 2018, and decreased on an equivalent basis per Boe by 46%. The decrease was primarily due to lower well servicing and maintenance costs of $6.8 million, pumping and gauging costs of $1.7 million, equipment rental costs of $1.3 million, and compression costs of $0.4 million. These decreases are due to improved cost management and the sale of our Mid-Continent assets on August 6, 2018. Partially offsetting these decreases is an increase in salt water disposal costs of $0.6 million. LOE per unit decreased on a higher percentage basis due to oil equivalent sales volumes being 33% higher during the year ended December 31, 2019 as compared to the same period in 2018.

Gas plant and midstream operating expense. Our gas plant and midstream operating expense increased $1.2 million to $12.0 million for the year ended December 31, 2019 from $10.8 million for the year ended December 31, 2018, and decreased on an equivalent basis per Boe by 17%. The increase was primarily due to an increase in compression costs of $2.4 million, facilities services and maintenance costs of $0.8 million, pumping and gauging costs of $0.6 million, and other equipment and rental costs of $0.4 million due to the Company's new oil gathering line to the Riverside Terminal that came online in July 2019. Partially offsetting these increases between the comparable periods is a reduction in our gas plant operating expenses of $3.0 million due to the sale of our Mid-Continent assets on August 6, 2018.

Gathering, transportation, and processing. Gathering, transportation, and processing expense increased by $7.0 million to $16.7 million for the year ended December 31, 2019 from $9.7 million for the year ended December 31, 2018. The increase was primarily due to additional sales contracts, in which natural gas production is sold at processing facilities' outlet meters, becoming effective during the first quarter of 2019. Due to the point of custody transfer, the revenues and gathering, transportation, and processing expense must be shown on a gross, rather than net, basis. In addition to the new contracts, sales volumes increased 33% as compared to the year ended December 31, 2018. Sales volumes have a direct correlation to gathering, transportation, and processing expense.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased by 35% to $25.6 million for the year ended December 31, 2019 from $19.0 million for the year ended December 31, 2018. Severance and ad valorem taxes primarily correlate to revenue. Revenue increased by 12% for the year ended December 31, 2019 when compared to the same period in 2018. The Company received a net ad valorem tax settlement of $5.1 million during the fourth quarter of 2018, which reduced this line item. Once that is factored in, the change between the comparable periods is immaterial. Please refer to *Part II, Item 8, Note 7 - Commitments and Contingencies* for additional discussion on the settlement.

Exploration. Our exploration expense increased $0.5 million to $0.8 million for the year ended December 31, 2019 from $0.3 million for the year ended December 31, 2018. The increase in exploration expense related primarily to geological and geophysical costs.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense increased 83% to $76.5 million for the year ended December 31, 2019 from $41.9 million for the year ended December 31, 2018, and increased 37% on a per boe basis during the comparable period. The increase in depreciation, depletion, and amortization correlates to a $215.8 million increase in the depletable property base in conjunction with an increase in the depletion rate driven by a substantial increase in production.

Abandonment and impairment of unproved properties. During the year ended December 31, 2019, we incurred $11.2 million in abandonment and impairment of unproved properties due to reassessment of estimated probable and possible reserve values and the expiration of non-core leases. During the year ended December 31, 2018, we incurred $5.3 million in abandonment and impairment of unproved properties due to the expiration of non-core leases. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional discussion on our impairment policy and practices.

General and administrative expense. Our general and administrative expense decreased by $2.8 million for the year ended December 31, 2019 to $39.7 million, compared to $42.5 million for the year ended December 31, 2018, and decreased by 30% on a per Boe basis between the comparable periods. The decrease in general and administrative expense between the comparable periods is primarily due to a decrease in salaries, benefits, and bonuses of $2.8 million resulting from an employee reduction effort in 2019 and restructuring fees of $1.1 million. Partially offsetting these decreases is an increase of severance costs of $0.5 million and professional services of $0.5 million. General and administrative expense per Boe decreased on a higher percentage basis due to oil equivalent sales volumes being 33% higher during the year ended December 31, 2019 as compared to the same period in 2018.

Derivative gain (loss). Our derivative loss for the year ended December 31, 2019 was $37.1 million as compared to a gain of $30.3 million for year ended December 31, 2018. Our derivative loss is primarily due to fair market value adjustments caused by market prices being higher than our contracted hedge prices. Please refer to *Part II, Item 8, Note 12 - Derivatives* for additional discussion.

Interest expense. Our interest expense for the years ended December 31, 2019 and 2018 was $2.7 million and $2.6 million, respectively. The Company incurred $3.5 million in interest expense associated with its Credit Facility, $1.1 million in commitment fees on the available borrowing base under the Credit Facility, and $0.5 million due to the amortization of deferred financing costs, offset by $2.4 million in capitalized interest during the year ended December 31, 2019. The Company incurred $1.4 million in interest expense associated with its Credit Facility and Prior Credit Facility, $0.9 million in commitment fees, and $0.3 million in miscellaneous fees related to its Credit Facility and Prior Credit Facility during the year ended December 31, 2018. Average debt outstanding for the years ended December 31, 2019 and 2018 was $77.2 million and $26.8 million, respectively.

Gain on sale of properties, net. We recorded a $1.2 million and $27.3 million gain on sale of properties during the years ended December 31, 2019 and December 31, 2018, respectively, primarily due to the sale of our Mid-Continent assets. Please refer to *Part II, Item 8, Note 3 - Divestitures* for additional discussion.

Liquidity and Capital Resources

The Company's anticipated sources of liquidity include cash from operating activities, borrowings under the Credit Facility, proceeds from sales of assets, and potential proceeds from equity and/or debt capital markets. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity, regulatory constraints, and other supply chain dynamics, among other factors. To mitigate some of the pricing risk, we have approximately 57% and 58% of our average 2020 guided oil production hedged as of December 31, 2019 and as of the filing date of this report, respectively, as oil constituted 85% of our oil and gas sales in 2019.

As of December 31, 2019, our liquidity was $281.0 million, consisting of cash on hand of $11.0 million and $270.0 million of available borrowing capacity on our Credit Facility. Please refer to *Part II, Item 8, Note 6 - Long-term Debt* for additional discussion.

We anticipate investing approximately $215 million to $235 million, which will support drilling approximately 61 gross wells, completing 45 gross wells, and turning to sales 62 gross wells in 2020.

The following table summarizes our cash flows and other financial measures for the periods indicated (in thousands).

	Year Ended December 31, 2019	Year Ended December 31, 2018
Net cash provided by operating activities	$ 224,647	$ 116,598
Net cash used in investing activities	(255,158)	(164,376)
Net cash provided by financing activities	28,604	47,998
Cash, cash equivalents, and restricted cash	11,095	13,002
Acquisition of oil and gas properties	(14,087)	(2,892)
Exploration and development of oil and gas properties	(242,487)	(264,231)

Cash flows provided by operating activities

For the years ended December 31, 2019 and 2018, the cash receipts and disbursements were attributable to our normal operating cycle. See *Results of Operations* above for more information on the factors driving these changes.

Cash flows used in investing activities

Expenditures for development of oil and natural gas properties are the primary use of our capital resources. The Company spent $242.5 million and $264.2 million on the exploration and development of oil and gas properties during the years ended December 31, 2019 and 2018, respectively. The decrease in capital expenditures between the periods is primarily due to reduced drilling activity as well as capital efficiencies and discipline. The Company also spent $11.2 million more on acquisitions of oil and gas properties during the year ended December 31, 2019 when compared to the same period in 2018.

Cash flows provided by financing activities

Net cash provided by financing activities for the years ended December 31, 2019 and 2018 was $28.6 million and $48.0 million, respectively, primarily due to net proceeds from our Credit Facility.

Credit Facility

On December 7, 2018, the Company entered into the Credit Facility. The Credit Facility had an aggregate original commitment amount of $750.0 million, an initial borrowing base of $350.0 million, and a maturity date of December 7, 2023. The Credit Facility borrowing base is redetermined on a semi-annual basis. The most recent redetermination was concluded on November 26, 2019, resulting in a reaffirmation of the borrowing base at $375.0 million; however, the Company chose to hold the aggregate elected commitments at $350.0 million. The next scheduled redetermination is set to occur in May 2020.

Borrowings under the Credit Facility bear interest at a per annum rate equal to, at the option of the Company, either (i) a London InterBank Offered Rate ("LIBOR"), subject to a 0% LIBOR floor plus a margin of 1.75% to 2.75%, based on the utilization of the Credit Facility (the "Eurodollar Rate") or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one month interest period, subject to a 0% LIBOR floor plus a margin of 0.75% to 1.75%, based on the utilization of the Credit Facility (the "Reference Rate"). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears.

The Credit Facility is guaranteed by all wholly owned subsidiaries of the Company (each, a "Guarantor" and, together with the Company, the "Credit Parties"), and is secured by first priority security interests on substantially all assets of each Credit Party, subject to customary exceptions.

The Credit Facility contains customary representations and affirmative covenants.

The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, and (xx) dividend payments. The Credit Parties are subject to certain financial covenants under the Credit Facility, including, without limitation, tested on the last day of each fiscal quarter, (i) a maximum ratio of the Company's consolidated indebtedness (subject to certain exclusions) to adjusted EBITDAX of 4.00 to 1.00 and (ii) a current ratio, as defined in the agreement, inclusive of the unused Commitments then available to be borrowed, to not be less than 1.00 to 1.00. The Company was in compliance with all covenants as of December 31, 2019 and through the filing date of this report.

Our weighted-average interest rates on borrowings from the Credit Facility were 4.4% and 4.7% for the years ended December 31, 2019 and 2018, respectively. As of December 31, 2019 and as of the date of filing, we had $80.0 million outstanding on our Credit Facility.

Non-GAAP Financial Measures

Adjusted EBITDAX represents earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash and non-recurring charges. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Facility based on adjusted EBITDAX ratios as further described above in *Liquidity and Capital Resources*. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table presents a reconciliation of the GAAP financial measure of net income to the non-GAAP financial measure of Adjusted EBITDAX (in thousands):

	Twelve Months Ended December 31,	
	2019	2018
Net income	$ 67,067	$ 168,186
Exploration	797	291
Depreciation, depletion and amortization	76,453	41,883
Amortization of deferred financing costs	248	30
Abandonment and impairment of unproved properties	11,201	5,271
Stock-based Compensation [(1)]	6,886	7,156
Cash severance costs [(1)]	751	279
Unused commitments	—	21
Gain on sale of oil and gas properties, net	(1,177)	(27,324)
Ad valorem reimbursement	—	(5,134)
Interest expense	2,650	2,603
Derivative (gain) loss	37,145	(30,271)
Derivative cash settlements	1,691	(18,160)
Adjusted EBITDAX	$ 203,712	$ 144,831

[(1)] Included as a portion of general and administrative expense in the accompanying statements of operations.

Contractual Obligations

We had the following contractual obligations and commitments as of December 31, 2019 (in thousands):

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Credit Facility[(1)]	$ 80,000	$ —	$ —	$ 80,000	$ —
Interest and fees on Credit Facility[(1)]	17,807	4,529	9,059	4,219	—
Delivery commitments[(2)]	80,999	22,474	47,325	11,200	—
Operating leases[(3)]	42,244	13,113	21,851	7,280	—
Asset retirement obligations[(4)]	84,035	—	18,415	1,476	64,144
Total	$ 305,085	$ 40,116	$ 96,650	$ 104,175	$ 64,144

(1) No scheduled payments exist for the Credit Facility, and prepayments can be made without penalty, so long as payment is made on the last day of the interest period. The interest is calculated using the stated rate within the Credit Facility for the current outstanding balance, and the commitment fees are based on the fees on the available borrowing base over the periods presented.

(2) The calculation on the delivery commitments is based on the minimum gross volume commitment schedule (as defined in the NGL Crude Logistics, LLC agreement) and applicable differential fees. Please refer to *Note 7 - Commitments and Contingencies* for additional discussion on this agreement.

(3) The Company has included the minimum future commitments for its long-term operating leases. Such leases are reflected at undiscounted values. Please refer to *Part II*, *Item* 8, *Note 2 - Leases*, for additional discussion

(4) Amounts represent our estimated future retirement obligations on an undiscounted basis. The discounted obligations are recorded as liabilities on our accompanying balance sheets as of December 31, 2019 and 2018. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. Please refer to *Part II*, *Item* 8, *Note 10 - Asset Retirement Obligation*, for additional discussion.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates, and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized at cost when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and other associated costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Costs of retired, sold, or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion, and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized. Gains or losses from the disposal of properties are recognized currently.

Expenditures for maintenance, repairs, and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements, and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties are supported by probable and possible well locations and cost incurred to acquire unproved leases. Unproved lease costs are capitalized until the leases expire or when probable and possible well locations are reassessed and entire areas are no longer represented, at which time we expense the associated unproved lease costs. The expensing or expiration of unproved lease costs are recorded as abandonment or impairment of unproved properties in the statements of operations and comprehensive income (loss) in our consolidated financial statements. Lease costs are reclassified to proved properties and depleted on a unit-of-production basis once proved reserves have been assigned.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and Standardized Measure

Our third-party petroleum consultant prepared our estimates of oil and natural gas reserves and associated future net revenues. While the SEC has adopted rules which allow us to disclose proved, probable, and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10-K. The SEC's revised rules define proved reserves as the 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. Our third party petroleum engineering consultant must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue Recognition

Sales of oil, natural gas, and NGLs are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies. Please refer to *Part II, Item* 8, *Note 1 - Summary of Significant Accounting Policies* for more information.

We record revenue in the month production is delivered to the purchaser. Payment is generally received within 30 to 60 days after the date of production. However, settlement statements for certain natural gas and NGLs sales may not be received for 30 to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. For the period from January 1, 2019 through December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company has interests with other producers in certain properties, in which case the Company uses the entitlement method to account for gas imbalances. The Company had no material gas imbalances as of December 31, 2019 and 2018.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred and at least annually. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs, using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

The unproved property balance at emergence from bankruptcy represents probable and possible well locations that are reassessed at least annually. The assessment of probable and possible locations incorporates key factors such as economic viability, surface constraints, wells per section, limitations on operatorship due to working interest changes, and any relevant components at such time. Changes in probable and possible locations that result in entire areas no longer being represented in the reserve run are impaired.

Leases acquired post-emergence are assessed for impairment applying the following factors:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases;
- our evaluation of the continuing successful results from the application of completion technology in the Wattenberg Field by us or by other operators in areas adjacent to or near our unproved properties; and
- strategic shifts in development areas.

The assessment of unproved properties to determine any possible impairment requires significant judgment.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation ("ARO") for oil and gas properties represents the estimated amount we will incur to plug, abandon, and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period, and the capitalized cost is depreciated on the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion, and amortization in our accompanying statements of operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes, and we do not enter into such instruments for speculative trading purposes. Derivative instruments are adjusted to fair value every accounting period. Derivative cash settlements and gains and losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under derivative gain (loss) in our accompanying statements of operations.

Stock-based compensation

Restricted Stock Units. We recognize compensation expense for all restricted stock units granted to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Stock-based compensation expense recorded for restricted stock units is included in general and administrative expenses on our accompanying statements of operations.

Performance Stock Units. We recognize compensation expense for all performance stock unit awards granted to employees. The number of shares of the Company's common stock that may be issued to settle Performance Stock Units ("PSUs") range from zero to two times the number of PSUs awarded. The PSUs vest in their entirety at the end of the three-year performance period. The total number of PSUs granted is evenly split between two performance criteria. The first criterion is based on a comparison of the Company's absolute and relative total shareholder return ("TSR") for the performance period compared with the TSRs of a group of peer companies for the same performance period. The TSR for the Company and each of the peer companies is determined by dividing (A)(i) the volume-weighted average share price for the last 30 trading days of the performance period, minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The second criterion is based on the Company's average annual return on capital employed ("ROCE") for each year during the three-year performance period. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period. Because these awards depend on a combination of performance-based settlement criteria and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected ROCE performance.

The fair value of the PSUs is measured at the grant date with a stochastic process method using a Brownian Motion simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's TSRs, the Company could not predict with certainty the path its stock price or the stock prices of its peers would take over the performance period. By using a stochastic simulation, the Company created multiple prospective stock pathways, statistically analyzed these simulations, and ultimately made inferences regarding the most likely path the stock price would take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Brownian Motion Model, was deemed an appropriate method by which to determine the fair value of the portion of the PSUs tied to the TSR. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the performance period, as well as the volatilities for each of the Company's peers.

Stock Options. We recognize compensation expense for all stock option awards granted to employees. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of stock option grants is based on a Black-Scholes Model. Stock-based compensation expense recorded for stock option awards is included in general and administrative expenses on our accompanying statements of operations.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance would be established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations, and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2019.

Recent accounting pronouncements

Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional details.

Effects of Inflation and Pricing

Inflation in the United States increased to 2.3% in 2019 from 2.2% in 2018 and from 1.8% in 2017. These changes did not have a material impact on our results of operations for the periods ended December 31, 2019, 2018, and 2017. Although the impact of inflation has been relatively insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, ARO, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money, and retain personnel.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risks.***

Oil and Natural Gas Price Risk

Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources. If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 0.3% and our PV-10 value as of December 31, 2019 would decrease by approximately 24% or $203.3 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 0.7% and our PV-10 value as of December 31, 2019 would increase by approximately 22% or $186.4 million.

PV-10 is a non-GAAP financial measure. Please refer to *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for management's discussion of this non-GAAP financial measure.

Commodity Derivative Contracts

Our primary commodity risk management objective is to protect the Company’s balance sheet via the reduction in cash flow volatility. We enter into derivative contracts for oil, natural gas, and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments. The types of derivative instruments that we use include swaps, collars, and puts.

Upon settlement of the contract(s), if the relevant market commodity price exceeds our contracted swap price, or the collar’s ceiling strike price, we are required to pay our counterparty the difference for the volume of production associated with the contract. Generally, this payment is made up to 15 business days prior to the receipt of cash payments from our customers. This could have an adverse impact on our cash flows for the period between derivative settlements and payments for revenue earned.

While we may reduce the potential negative impact of lower commodity prices, we may also be prevented from realizing the benefits of favorable price changes in the physical market.

Presently, our derivative contracts have been executed with seven counterparties, all of which are members of our Credit Facility syndicate. We enter into contracts with counterparties whom we believe are well capitalized. However, if our counterparties fail to perform their obligations under the contracts, we could suffer financial loss.

Please refer to the *Derivative Activities* section of Part I, Item 1 of this Annual Report on Form 10-K for summary derivative activity tables.

For the oil and natural gas derivatives outstanding at December 31, 2019, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2019 would increase our derivative loss by $21.7 million or decrease it by $19.3 million, respectively.

Interest Rates

At both December 31, 2019 and on the filing date of this report, we had $80.0 million outstanding under our Credit Facility. Borrowings under our Credit Facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. As of December 31, 2019 and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants.

Counterparty and Customer Credit Risk

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Seven lenders under our Credit Facility are currently counterparties on our derivative instruments currently in place and have investment grade credit ratings.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. Please refer to the section titled *Principal Customers* under Part I, Item 1 of this Annual Report on Form 10-K for further details about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history, and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production depends in part upon the availability, proximity, and capacity of third-party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems, and processing facilities. We deliver crude oil and natural gas produced through trucking services, pipelines, and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, weather, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no pipeline systems that service wells in our French Lake area of the Wattenberg Field. If neither we nor a third-party constructs the required pipeline system, we may not be able to fully test or develop our resources in French Lake.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Bonanza Creek Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Bonanza Creek Energy, Inc. and subsidiaries (the "Company") as of December 31, 2019, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows, for the year ended December 31, 2019, 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, 2019, and the results of its operations and its cash flows for the year ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2020, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 audit. We are a public accounting firm registered with the 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 audit 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. Our audit 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 audit 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 audit provides a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

February 27, 2020
Denver, Colorado

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

Report of Independent Registered Accounting Firm

Board of Directors and Stockholders
Bonanza Creek Energy, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheet of Bonanza Creek Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2018, and the related consolidated statements of operations and comprehensive income (loss), stockholders’ equity, and cash flows for the year ended December 31, 2018 and for the period from April 29, 2017 through December 31, 2017 (Successor) and the period from January 1, 2017 through April 28, 2017 (Predecessor), 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, 2018, and the results of its operations and its cash flows for the year ended December 31, 2018 and for the period from April 29, 2017 through December 31, 2017 (Successor) and the period from January 1, 2017 through April 28, 2017 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

Change in accounting principles
As discussed in Note 1 to the consolidated statements, the Company has changed its method of accounting for revenue from contracts with customers due to the adoption of the new revenue standard using the modified retrospective approach. Our opinion is not modified with respect to this matter.

Basis of presentation
As discussed in Note 1 to the consolidated financial statements, the United States Bankruptcy Court for the District of Delaware entered an order confirming the plan for reorganization on April 7, 2017, and the Company emerged from bankruptcy on April 28, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with FASB Accounting Standards Codification 852, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods, as described in Note 1.

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 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. 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 supporting 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.

/s/ GRANT THORNTON LLP

We served as the Company’s auditor from 2017 to 2019.

Oklahoma City, Oklahoma
February 27, 2019

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	As of December 31, 2019	As of December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,008	$ 12,916
Accounts receivable:		
Oil and gas sales	43,714	31,799
Joint interest and other	38,136	47,577
Prepaid expenses and other	7,048	4,633
Inventory of oilfield equipment	7,726	3,478
Derivative assets (note 12)	2,884	34,408
Total current assets	110,516	134,811
Property and equipment (successful efforts method):		
Proved properties	935,025	719,198
Less: accumulated depreciation, depletion and amortization	(126,614)	(52,842)
Total proved properties, net	808,411	666,356
Unproved properties	143,020	154,352
Wells in progress	98,750	93,617
Other property and equipment, net of accumulated depreciation of $3,142 in 2019 and $2,546 in 2018	3,394	3,649
Total property and equipment, net	1,053,575	917,974
Long-term derivative assets (note 12)	121	3,864
Right-of-use assets (note 2)	38,562	—
Other noncurrent assets (note 4)	3,544	4,885
Total assets	$ 1,206,318	$ 1,061,534
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 5)	$ 57,638	$ 79,390
Oil and gas revenue distribution payable	29,021	19,903
Lease liability (note 2)	11,690	—
Derivative liability (note 12)	6,390	183
Total current liabilities	104,739	99,476
Long-term liabilities:		
Credit facility (note 6)	80,000	50,000
Lease liability (note 2)	27,540	—
Ad valorem taxes	28,520	18,740
Derivative liability (note (12)	921	—
Asset retirement obligations for oil and gas properties (note 10)	27,908	29,405
Total liabilities	269,628	197,621
Commitments and contingencies (note 7)		
Stockholders' equity:		
Preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 225,000,000 shares authorized, 20,643,738 and 20,543,940 issued and outstanding as of December 31, 2019 and 2018, respectively	4,284	4,286
Additional paid-in capital	702,173	696,461
Retained earnings	230,233	163,166
Total stockholders' equity	936,690	863,913
Total liabilities and stockholders' equity	$ 1,206,318	$ 1,061,534

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except per share amounts)

	Successor			Predecessor
	For the Year Ended December 31, 2019	For the Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Operating net revenues:				
Oil and gas sales	$ 313,220	$ 276,657	$ 123,535	$ 68,589
Operating expenses:				
Lease operating expense	25,249	34,825	25,862	13,128
Gas plant and midstream operating expense	12,014	10,788	8,341	3,541
Gathering, transportation, and processing	16,682	9,732	—	—
Severance and ad valorem taxes	25,598	18,999	9,590	5,671
Exploration	797	291	3,745	3,699
Depreciation, depletion, and amortization	76,453	41,883	21,312	28,065
Abandonment and impairment of unproved properties	11,201	5,271	—	—
Unused commitments	—	21	—	993
General and administrative expense (including $6,886, $7,156, $11,630, and $2,116, respectively, of stock-based compensation)	39,668	42,453	42,676	15,092
Total operating expenses	207,662	164,263	111,526	70,189
Other income (expense):				
Derivative gain (loss)	(37,145)	30,271	(15,365)	—
Interest expense, net	(2,650)	(2,603)	(773)	(5,656)
Gain on sale of properties, net	1,177	27,324	—	—
Reorganization items, net (note 15)	—	—	—	8,808
Other income (expense)	127	800	(1,267)	1,108
Total other income (expense)	(38,491)	55,792	(17,405)	4,260
Income (loss) from operations before taxes	67,067	168,186	(5,396)	2,660
Current income tax benefit (expense) (note 9)	—	—	376	—
Net income (loss)	$ 67,067	$ 168,186	$ (5,020)	$ 2,660
Comprehensive income (loss)	$ 67,067	$ 168,186	$ (5,020)	$ 2,660
Net income (loss) per common share:				
Basic	$ 3.25	$ 8.20	$ (0.25)	$ 0.05
Diluted	$ 3.24	$ 8.16	$ (0.25)	$ 0.05
Weighted-average common shares outstanding				
Basic	20,612	20,507	20,427	49,559
Diluted	20,681	20,603	20,427	50,971

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-In	Accumulated Earnings	
	Shares	Amount	Capital	(Deficit)	Total
	(in thousands, except share data)				
Balances, January 1, 2017 (Predecessor)	49,660,683	$ 49	$ 814,990	$ (795,978)	$ 19,061
Restricted common stock issued	767,848	1	—	—	1
Restricted common stock forfeited	(5,134)	—	—	—	—
Restricted stock used for tax withholdings	(318,180)	(1)	(427)	—	(428)
Fair value of equity issued to existing common stockholders	—	—	(23,410)	—	(23,410)
Stock-based compensation	—	—	2,116	—	2,116
Net income	—	—	—	2,660	2,660
Balances, April 28, 2017 (Predecessor)	50,105,217	$ 49	$ 793,269	$ (793,318)	$ —
Cancellation of Predecessor equity	(50,105,217)	(49)	(793,269)	793,318	—
Balances, April 28, 2017 (Predecessor)	—	$ —	$ —	$ —	$ —
Issuance of Successor equity	20,356,071	$ 4,285	$ 679,836	$ —	$ 684,121
Balances, April 28, 2017 (Successor)	20,356,071	$ 4,285	$ 679,836	$ —	$ 684,121
Restricted common stock issued	173,200	2	—	—	2
Restricted stock used for tax withholdings	(75,722)	(1)	(2,398)	—	(2,399)
Stock-based compensation	—	—	11,630	—	11,630
Net loss	—	—	—	(5,020)	(5,020)
Balances, December 31, 2017 (Successor)	20,453,549	$ 4,286	$ 689,068	$ (5,020)	$ 688,334
Restricted common stock issued	84,345	—	—	—	—
Restricted stock used for tax withholdings	(25,991)	—	(863)	—	(863)
Exercise of stock options	32,037	—	1,100	—	1,100
Stock-based compensation	—	—	7,156	—	7,156
Net income	—	—	—	168,186	168,186
Balances, December 31, 2018 (Successor)	20,543,940	$ 4,286	$ 696,461	$ 163,166	$ 863,913
Restricted common stock issued	146,359	—	—	—	—
Restricted stock used for tax withholdings	(46,561)	(2)	(1,174)	—	(1,176)
Stock-based compensation	—	—	6,886	—	6,886
Net income	—	—	—	67,067	67,067
Balances, December 31, 2019 (Successor)	20,643,738	$ 4,284	$ 702,173	$ 230,233	$ 936,690

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Cash flows from operating activities:				
Net income (loss)	$ 67,067	$ 168,186	$ (5,020)	$ 2,660
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	76,453	41,883	21,312	28,065
Non-cash reorganization items	—	—	—	(44,160)
Abandonment and impairment of unproved properties	11,201	5,271	—	—
Well abandonment costs and dry hole expense	172	—	75	2,931
Stock-based compensation	6,886	7,156	11,630	2,116
Non-cash lease expense	668	—	—	—
Amortization of deferred financing costs and debt premium	487	30	—	374
Derivative (gain) loss	37,145	(30,271)	15,365	—
Derivative cash settlements	1,691	(18,160)	(1,464)	—
Gain on sale of oil and gas properties	(1,177)	(27,324)	—	—
Inventory write-offs	—	248	1,758	—
Other	3,559	(3,559)	11	18
Changes in current assets and liabilities:				
Accounts receivable	(2,688)	(46,988)	(4,477)	(6,640)
Prepaid expenses and other assets	(2,415)	2,214	(1,979)	963
Accounts payable and accrued liabilities	28,320	19,953	(8,470)	(5,880)
Settlement of asset retirement obligations	(2,722)	(2,041)	(1,167)	(331)
Net cash provided by (used in) operating activities	224,647	116,598	27,574	(19,884)
Cash flows from investing activities:				
Acquisition of oil and gas properties	(14,087)	(2,892)	(5,383)	(445)
Exploration and development of oil and gas properties	(242,487)	(264,231)	(76,384)	(5,123)
Proceeds from sale of oil and gas properties	1,757	103,134	—	—
Additions to property and equipment - non oil and gas	(341)	(387)	(874)	(454)
Net cash used in investing activities	(255,158)	(164,376)	(82,641)	(6,022)
Cash flows from financing activities:				
Proceeds from credit facility	55,000	140,000	—	—
Payments to credit facility	(25,000)	(90,000)	—	(191,667)
Proceeds from sale of common stock	—	—	—	207,500
Proceeds from exercise of stock options	—	1,100	—	—
Payment of employee tax withholdings in exchange for the return of common stock	(1,176)	(863)	(2,398)	(427)
Deferred financing costs	(220)	(2,239)	—	—
Net cash provided by (used in) financing activities	28,604	47,998	(2,398)	15,406
Net change in cash, cash equivalents, and restricted cash	(1,907)	220	(57,465)	(10,500)
Cash, cash equivalents, and restricted cash:				
Beginning of period	13,002	12,782	70,247	80,747
End of period	$ 11,095	$ 13,002	$ 12,782	$ 70,247
Supplemental cash flow disclosure:				
Cash paid for interest, net of capitalization	$ 4,110	$ 2,582	$ 523	$ 3,509
Severance and ad valorem tax refund	$ 352	$ —	$ —	$ —
Cash paid for reorganization items	$ —	$ —	$ —	$ 52,968
Changes in working capital related to drilling expenditures	$ 30,354	$ 11,769	$ 16,057	$ 3,360
Cash paid for amounts included in the measurement of lease liabilities	$ 10,993	$ —	$ —	$ —

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations

Bonanza Creek Energy, Inc. (“BCEI” or, together with its consolidated subsidiaries, the “Company”) is engaged primarily in acquiring, developing, extracting, and producing oil and gas properties. The Company’s assets and operations are concentrated in the rural portions of the Wattenberg Field in Weld County, Colorado.

Basis of Presentation

As of December 31, 2019, the consolidated balance sheets (“balance sheets”) include the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Holmes Eastern Company, LLC, and Rocky Mountain Infrastructure, LLC. All intercompany accounts and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to the current period presentation. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2019, through the filing date of this report.

On August 6, 2018, the Company sold its equity interests in Bonanza Creek Energy Resources, LLC, which owns all of the outstanding equity interest in Bonanza Creek Energy Upstream LLC and Bonanza Creek Energy Midstream, LLC. These subsidiaries comprised the Company's Mid-Continent region and assets. Please refer to *Note 3 - Divestitures* for additional discussion.

On January 4, 2017, the Company and certain of its subsidiaries (collectively with the Company, the “Debtors”) filed voluntary petitions (the “Bankruptcy Petitions,” and the cases commenced thereby, the “Chapter 11 Cases”) under Chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the District of Delaware (the “Bankruptcy Court”) to pursue the Debtors’ Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (as proposed, the “Plan”). The Bankruptcy Court granted the Debtors' motion seeking to administer all of the Debtors' Chapter 11 Cases jointly under the caption “In re Bonanza Creek Energy, Inc., et al” (Case No. 17-10015). The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017 (the “Effective Date”). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession during a portion of the year ended December 31, 2017. As such, certain aspects of the bankruptcy proceedings of the Company and related matters are described below in order to provide context and explain part of our financial condition and results of operations for the period presented.

Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. As a result of the application of fresh-start accounting and the effects of the implementation of the Plan, the Company’s condensed consolidated financial statements after April 28, 2017 are not comparable with the financial statements on or prior to April 28, 2017. The Company's condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after April 28, 2017 and dates prior thereto. Please refer to *Note 15 - Fresh-Start Accounting* for additional discussion.

Subsequent to January 4, 2017 and through the date of emergence, all expenses, gains, and losses directly associated with the reorganization are reported as reorganization items, net in the accompanying consolidated statements of operations and comprehensive income (loss) (“statements of operations”).

References to “Successor” or “Successor Company” relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to “Predecessor” or “Predecessor Company” relate to the financial position and results of operations of the Company on or prior to April 28, 2017. Throughout these financial statements, the Company refers to the 2017 annual period which is comprised of both Successor and Predecessor periods. References to “2017 Successor Period” relate to the period of April 29, 2017 through December 31, 2017. References to the “2017 Predecessor Period” relate to the period of January 1, 2017 through April 28, 2017.

Use of Estimates

The preparation of the Company’s 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 oil and gas reserves, assets and liabilities, and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Going Concern Presumption

Our consolidated financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets, and the satisfaction of liabilities and other commitments in the normal course of business.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximate fair value due to the short-term nature of these instruments.

Accounts Receivable

The Company’s accounts receivables are generated from oil and gas sales and from joint interest owners on properties that the Company operates. These receivables are generally unsecured. The Company accrues an allowance on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any allowance may be reasonably estimated. For receivables from joint interest owners, the Company usually has the ability to withhold future revenue disbursements to satisfy the outstanding balance. The Company’s oil and gas receivables are typically collected within one to two months, and the Company has experienced minimal bad debts.

Inventory of Oilfield Equipment

Inventory consists of material and supplies used in connection with the Company’s drilling program. These inventories are stated at the lower of cost or net realizable value, which approximates fair value.

Oil and Gas Producing Activities

The Company follows the successful efforts method of accounting for its oil and gas exploration and development costs. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells will be capitalized at cost when incurred, pending determination of whether economically recoverable reserves have been found. If an exploratory well does not find economically recoverable reserves, the costs of drilling the well and other associated costs are charged to dry hole expense. The costs of development wells are capitalized whether the well is productive or nonproductive. Costs incurred to maintain wells and their related equipment and leases as well as operating costs are charged to expense as incurred. Geological and geophysical costs are expensed as incurred.

Depletion, depreciation, and amortization (“DD&A”) of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and anticipated proceeds from salvaging equipment.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to fair value. The factors used to determine fair value are subject to the Company’s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows on all developed proved reserves and risk adjusted probable and possible reserves, net of estimated operating and development costs, future commodity pricing based on the Company's internal budgeting model originating from the NYMEX strip price adjusted for basis differential, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

As of December 31, 2019, the Company's gathering assets comprised $146.4 million, $1.3 million, and $0.1 million of proved properties, wells in progress, and unproved properties, respectively, on the accompanying balance sheets. Depreciation on the Company's gathering assets is calculated using the straight-line method over the estimated useful lives of the assets and the assets it is servicing, which is approximately 30 years.

Unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis once proved reserves have been assigned. The unproved property balance at emergence from bankruptcy represents probable and possible well locations that are reassessed at least annually. The assessment of probable and possible locations incorporates key factors such as economic viability, surface constraints, wells per section, limitations on operatorship due to working interest changes, and any relevant components at such time. Changes in probable and possible locations that result in entire areas no longer being represented in the reserve run are impaired. Leases acquired post-emergence are assessed for impairment applying the following factors:

- the remaining amount of unexpired term under leases;
- the Company's ability to actively manage and prioritize its capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- its ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases;
- its evaluation of the continuing successful results from the application of completion technology by the Company or by other operators in areas adjacent to or near its unproved properties; and
- strategic shifts in development areas.

The Company records the fair value of an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. The increase in carrying value is included in proved properties in the accompanying balance sheets. For additional discussion, please refer to *Note 10 - Asset Retirement Obligations.*

Gains and losses arising from sales of oil and gas properties will be included in income. However, a partial sale of proved properties within an existing field that does not significantly affect the unit-of-production depletion rate will be accounted for as a normal retirement with no gain or loss recognized. The sale of a partial interest within a proved property is accounted for as a recovery of cost. The partial sale of unproved property is accounted for as a recovery of cost when there is uncertainty of the ultimate recovery of the cost applicable to the interest retained.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Cost of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed as incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Any subsequent decreases to the estimated fair value less the costs to sell impact the measurement of assets held for sale. Any properties deemed held for sale as of the balance sheet date are presented separately on the accompanying balance sheets at the lower of net book value or fair value less cost to sell. Please refer to *Note 3 - Divestitures* for more information.

Revenue Recognition

On January 1, 2018, the Company adopted Accounting Standards Codification (“ASC”) 606 (“ASC 606”), *Revenue from Contracts with Customers,* using the modified retrospective approach. Sales of oil, natural gas, and NGLs are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. The Company's contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies.

As further described in *Note 7 - Commitments and Contingencies*, one contract with NGL Crude has an additional aspect of variable consideration related to the minimum volume commitments (“MVCs”) as specified in the agreement. On an on-going basis, the Company performs an analysis of expected risk adjusted production applicable to the NGL Crude agreement based on approved production plans to determine if liquidated damages to NGL Crude are probable. As of December 31, 2019, the Company believes that the volumes delivered to NGL Crude will be in excess of the MVCs required then and for the upcoming approved production plan. As a result of this analysis, to date, no variable consideration related to potential liquidated damages has been considered in the transaction price for the NGL Crude agreement.

Under the oil sales contracts, the Company sells oil production at the wellhead, or other contractually agreed-upon delivery points, and collect an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the wellhead, or other contractually agreed-upon delivery point, at the net contracted price received.

Under the natural gas processing contracts, the Company delivers natural gas to an agreed-upon delivery point. The delivery points are specified within each contract, and the transfer of control varies between the inlet and outlet of the midstream processing facility. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs and residue gas. For the contracts where the Company maintains control through the outlet of the midstream processing facility, the Company recognizes revenue on a gross basis, with gathering, transportation, and processing fees presented as an expense in the Company's accompanying statements of operations. Alternatively, for those contracts where the Company relinquishes control at the inlet of the midstream processing facility, the Company recognizes natural gas and NGLs revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, the Company recognizes revenue on a net basis.

Under the product sales contracts, the Company invoices customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under this guidance. At December 31, 2019 and 2018, the Company's receivables from contracts with customers were $43.7 million and $31.8 million, respectively. Payment is generally received within 30 to 60 days after the date of production.

The Company records revenue in the month production is delivered to the purchaser. However, as stated above, settlement statements for certain natural gas and NGLs sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between our estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. For the period from January 1, 2019 through December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Revenue attributable to each of our identified revenue streams is disaggregated below (in thousands) for the periods following the adoption of ASC 606:

	For the years ended December 31,	
	2019	2018
Operating Revenues:		
Crude oil sales	$ 268,865	$ 228,661
Natural gas sales	28,296	22,369
Natural gas liquids sales	16,059	25,627
Oil and gas sales	$ 313,220	$ 276,657

Income Taxes

The Company accounts for income taxes under the liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Uncertain Tax Positions

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The tax returns for 2018, 2017, and 2016 are still subject to audit by the Internal Revenue Service. There were no uncertain tax positions during any period presented.

Concentrations of Credit Risk

The Company maintains cash balances in excess of the Federal Deposit Insurance Corporation (FDIC) insured limit.

The Company is exposed to credit risk in the event of nonpayment by counterparties whose creditworthiness is continuously evaluated. For the years ended December 31, 2019, 2018, and 2017, NGL Crude Logistics accounted for 82%, 66%, and 44% of sales, respectively; Lion Oil Trading & Transportation, Inc. accounted for 0%, 8%, and 18% of sales, respectively; and Duke Energy Field Services accounted for 6%, 8%, and 16% of sales, respectively.

Oil and Gas Derivative Activities

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts. The contracts are placed with major financial institutions and take the form of swaps, collars, or puts. The oil contracts are indexed to NYMEX WTI prices, and natural gas contracts are indexed to NYMEX HH and CIG prices, which have a high degree of historical correlation with actual prices received by the Company, before differentials. The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value. For additional discussion, please refer to *Note 12 - Derivatives*.

Earnings Per Share

Earnings per basic and diluted share within the Successor Company are calculated under the treasury stock method. Basic net income (loss) per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. Diluted net income (loss) per common share is calculated by dividing net income (loss) by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested restricted stock units (“RSUs”), in-the-money outstanding stock options, unvested performance stock units (“PSUs”), and exercisable warrants. When the Company recognizes a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted earnings per share.

Earnings per basic and diluted share within the Predecessor Company were calculated under the two-class method. Pursuant to the two-class method, the Company’s unvested restricted stock awards with non-forfeitable rights to dividends are considered participating securities. Under the two-class method, earnings per basic share is calculated by dividing net income available to shareholders by the weighted-average number of common shares outstanding during the period. The two-class method includes an earnings allocation formula that determines earnings per share for each participating security according to undistributed earnings for the period. Net income available to shareholders is reduced by the amount allocated to participating restricted shares to arrive at the earnings allocated to common stock shareholders for purposes of calculating earnings per share. Participating shares are not contractually obligated to share in the losses of the Company, and therefore, the entire net loss is allocated to the outstanding shares. Earnings per diluted share is computed on the basis of the weighted-average number of common shares outstanding during the period plus the dilutive effect of any potential common shares outstanding during the period using the more dilutive of the treasury method or two-class method. For additional discussion, please refer to *Note 13 - Earnings Per Share*.

Stock-Based Compensation

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. For additional discussion, please refer to *Note 8 - Stock-Based Compensation*.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, trade receivables, trade payables, accrued liabilities, credit facilities, and derivative instruments. Cash and cash equivalents, trade receivables, trade payables, and accrued liabilities are carried at cost and approximate fair value due to the short-term nature of these instruments. Our credit facilities have variable interest rates, so they approximate fair value. Derivative instruments are recorded at fair value.

Restricted Cash

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets, which sums to the total of such amounts shown in the accompanying consolidated statements of cash flows (in thousands):

	As of December 31,			As of
	2019	2018	2017	April 28, 2017
Cash and cash equivalents	$ 11,008	$ 12,916	$ 12,711	$ 70,183
Restricted cash included in other noncurrent assets[(1)]	87	86	71	64
Total cash, cash equivalents and restricted cash as shown in the statements of cash flows	$ 11,095	$ 13,002	$ 12,782	$ 70,247

(1) Consists of funds for road maintenance and repairs

Recently Issued and Adopted Accounting Standards

In February 2016, the FASB issued *Update No. 2016-02 - Leases (ASC 842)* to increase transparency and comparability among organizations by recognizing right-of-use assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Each lease that is recognized in the balance sheet will be classified as either finance or operating requiring certain quantitative and qualitative disclosures. Leases acquired to explore the development of oil and natural gas resources are not within the scope of this guidance. The new standard was adopted using the optional transition approach at the date of initial application on January 1, 2019. Please refer to *Note 2 - Leases* for additional disclosure.

In June 2016, the FASB issued *Update No. 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The update changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amended standard is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted, and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. Historically, the Company's credit losses on oil and natural gas sales receivables and joint interest receivables have not been significant, and the Company does not believe the adoption of this standard will have a material impact on its consolidated financial statements.

In August 2018, the FASB issued *Update No. 2018-13, Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*. The objective of this update is to improve the effectiveness of fair value measurement disclosures. This update is effective for annual periods beginning after December 15, 2019, and interim periods within those annual periods. The standard will only impact the form of the Company's disclosures.

There are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and disclosures that have been issued but not yet adopted by the Company as of December 31, 2019, and through the filing date of this report.

NOTE 2 - LEASES

On January 1, 2019, the Company adopted ASC 842 using the optional transition approach prescribed in *Updated No 2018-11 - Lease (Topic 842), Targeted Improvements*. Under this approach, results for reporting periods beginning January 1, 2019 are presented in accordance with ASC 842, while prior period amounts are reported in accordance with *ASC 840 - Leases*. The Company recognized $32.8 million and $33.6 million in right-of-use assets and lease liabilities, respectively, on January 1, 2019, representing lease payment obligations associated with compressors, vehicles, office space, and other field and corporate equipment with contractual durations in excess of one year. The difference between the right-of-use assets and the total lease liability was related to a deferred rent balance of $0.8 million, which were required to be netted against the right-of-use assets as of the implementation date of January 1, 2019. There was no cumulative-effect adjustment to retained earnings upon adoption of the new standard.

ASC 842 provided certain practical expedients, of which the Company elected (i) to account for lease and non-lease components in its contracts as a single lease component for all asset classes, (ii) to adopt the land easement practical expedient, which allows the Company to apply ASC 842 prospectively to new or modified land easements beginning January 1, 2019, and (iii) to not apply the recognition requirements of ASC 842 to leases with a lease term of twelve months or less. The Company's leasing activities as a lessor are negligible.

During the year ended December 31, 2019, the Company incurred $16.6 million in new right-of-use assets and lease liabilities. The Company's right-of-use assets and lease liabilities are recognized at their discounted present value on the balance sheet at $38.6 million and $39.2 million as of December 31, 2019, respectively. All leases recognized on the Company's balance sheet are classified as operating leases, which include leases related to the asset classes reflected in the table below (in thousands):

	Right-of-use Asset	Lease Liability
Field equipment(1)	$ 35,057	$ 35,075
Corporate leases	2,462	3,129
Vehicles	1,043	1,026
Total	$ 38,562	$ 39,230

(1) Includes compressors, certain gas processing equipment, and other field equipment.

The lease amounts disclosed are presented on a gross basis. A portion of these costs may have been or will be billed to other working interest owners, and the Company's net share of these costs, once paid, are included in proved properties, other property and equipment, lease operating expenses, or general and administrative expenses, as applicable.

The Company recognizes lease expense on a straight-line basis excluding short-term and variable lease payments, which are recognized as incurred. Short-term lease cost represents payments for leases with a lease term of one year or less, excluding leases with a term of one month or less. Short-term leases include drilling rigs and other equipment. Drilling rig contracts are structured based on an allotted number of wells to be drilled consecutively at a daily operating rate. Short-term drilling rig costs include a non-lease labor component, which is treated as a single lease component.

The following table summarizes the components of the Company's gross operating lease costs incurred during the year ended December 31, 2019 (in thousands):

	Twelve Months Ended December 31, 2019
Operating lease cost(1)	$ 11,330
Short-term lease cost	8,169
Variable lease cost(2)	259
Sublease income(3)	(348)
Total lease cost	$ 19,410

(1) Includes office rent expense of $1.1 million for the year ended December 31, 2019.
(2) Variable lease cost represents differences between lease obligations and actual costs incurred for certain leases that do not have fixed payments related to both lease and non-lease components. Such incremental costs include lease payment increases or decreases driven by market price fluctuations and leased asset maintenance costs.
(3) The Company subleased a portion of its office space for the remainder of the office lease term.

The Company does not have any leases with an implicit interest rate that can be readily determined. As a result, the Company used the incremental borrowing rate, based on the Credit Facility benchmark rate, adjusted for facility utilization and lease term, to calculate the respective discount rates. Please refer to *Note 6 - Long-term Debt* for additional information.

The Company has certain lease agreements that provide for the option to extend or terminate early, which was evaluated on each lease to arrive at the proper lease term. There were some leases that the option to extend was factored into the resulting lease term. There were no leases where early termination was factored into the resulting lease term. The Company's weighted-average remaining lease term and discount rate used during the year ended December 31, 2019 are as follows:

	Twelve Months Ended December, 2019
Weighted-average lease term (years)	3.5
Weighted-average discount rate	4.33%

Future commitments by year for the Company's operating leases with a lease term of one year or more as of December 31, 2019 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the balance sheet as follows (in thousands):

	Amount
2020	$ 13,113
2021	11,823
2022	10,028
2023	5,721
2024	1,559
Thereafter	—
Total lease payments	42,244
Less: imputed interest	(3,014)
Total lease liability	$ 39,230

Future minimum lease payments related to the Company's operating leases as of December 31, 2018 are presented below (in thousands):

	Amount[1]
2019	1,256
2020	1,351
2021	1,401
2022	234
2023	—
Thereafter	—
Total	$ 4,242

(1) Consists of future minimum lease payments not reported on the balance sheet in accordance with *ASC 840 - Leases*.

NOTE 3 - DIVESTITURES

During the first quarter of 2018, the Company established a plan to sell all of the Company's assets within its Mid-Continent region and North Park Basin in order to focus on and partially fund the development of its core assets in the Wattenberg Field in Colorado, at which point they were deemed held for sale.

The Company sold its North Park Basin assets on March 9, 2018 for minimal net proceeds and full release of all current and future obligations resulting in a minimal net loss.

On August 6, 2018, the Company entered into an agreement to simultaneously close and divest of all of its assets within its Mid-Continent region. Net proceeds, including 2019 purchase price adjustments, the sale amounted to $103.5 million resulting in a gain of approximately $28.6 million, net of purchase price adjustments, included in the gain on sale of properties, net line item in the accompanying statements of operations.

NOTE 4 - OTHER NONCURRENT ASSETS

Other noncurrent assets contain the following (in thousands):

	As of December 31,	
	2019	2018
Operating bonds	$ 1,638	$ 2,713
Deferred financing costs	1,443	1,710
AMT credit refund[1]	376	376
Restricted cash	87	86
Other noncurrent assets	$ 3,544	$ 4,885

(1) Represents the alternative minimum tax credit refund due to the Company upon application of the newly enacted comprehensive tax legislation that took effect on December 22, 2017.

NOTE 5 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

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

	As of December 31,	
	2019	2018
Drilling and completion costs	$ 3,248	$ 33,602
Accounts payable trade	17,117	11,532
Accrued general and administrative cost	5,620	12,728
Lease operating expense	2,187	2,183
Accrued interest	692	241
Accrued oil and gas hedging	453	—
Production and ad valorem taxes and other	28,321	19,104
Total accounts payable and accrued expenses	$ 57,638	$ 79,390

NOTE 6 - LONG-TERM DEBT

Successor Debt

Credit Facility

On December 7, 2018, the Company entered into a reserve-based revolving facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions, as lenders (the “Credit Facility”). The Credit Facility has an aggregate original commitment amount of $750.0 million, an initial borrowing base of $350.0 million, and a maturity date of December 7, 2023. The Credit Facility borrowing base is redetermined on a semi-annual basis. The most recent redetermination was concluded on November 26, 2019, resulting in a reaffirmation of the borrowing base at $375.0 million; however, the Company chose to hold the aggregate elected commitments at $350.0 million. The next scheduled redetermination is set to occur in May 2020.

Borrowings under the Credit Facility bear interest at a per annum rate equal to, at the option of the Company, either (i) a London InterBank Offered Rate (“LIBOR”), subject to a 0% LIBOR floor plus a margin of 1.75% to 2.75%, based on the utilization of the Credit Facility (the “Eurodollar Rate”) or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one month interest period, subject to a 0% LIBOR floor plus a margin of 0.75% to 1.75%, based on the utilization of the Credit Facility (the “Reference Rate”). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears. The Company's Credit Facility approximates fair value as the applicable interest rates are floating.

The Credit Facility is guaranteed by all wholly owned subsidiaries of the Company (each, a “Guarantor” and, together with the Company, the “Credit Parties”), and is secured by first priority security interests on substantially all assets of each Credit Party, subject to customary exceptions.

The Credit Facility contains customary representations and affirmative covenants.

The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, and (xx) dividend payments. The Credit Parties are subject to certain financial covenants under the Credit Facility, including, without limitation, tested on the last day of each fiscal quarter, (i) a maximum ratio of the Company’s consolidated indebtedness (subject to certain exclusions) to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash charges (“EBITDAX”) of 4.00 to 1.00 and (ii) a current ratio, as defined in the agreement, inclusive of the unused Commitments then available to be borrowed, to not be less than 1.00 to 1.00. The Company was in compliance with all covenants as of December 31, 2019 and through the filing date of this report.

The Company had $80.0 million and $50.0 million outstanding on the Credit Facility as of December 31, 2019 and 2018, respectively. As of the date of filing, the Company had $80.0 million outstanding on its Credit Facility.

In connection with the Credit Facility, the Company capitalized a total of $2.5 million in deferred financing costs. Of the total post-amortization net capitalized amounts, $1.4 million and $1.7 million as of December 31, 2019 and 2018, respectively, are presented within other noncurrent assets, and $0.5 million as of December 31, 2019 and 2018, respectively, are presented within prepaid expenses and other line items in the accompanying balance sheets.

Prior Credit Facility

On the Effective Date, the Company entered into a revolving credit facility, as the borrower, with KeyBank National Association, as the administrative agent, and certain lenders party thereto (the "Prior Credit Facility"). The borrowing base was $191.7 million and had a maturity date of March 31, 2021.

The Prior Credit Facility stated the Company's leverage ratio of indebtedness to EBITDAX was not to exceed 3.50 to 1.00, the minimum current ratio had to be 1.00 to 1.00, and the minimum interest coverage ratio of trailing twelve-month EBITDAX to trailing twelve-month interest expense had to be 2.50 to 1.00 as of the end of the respective fiscal quarter. During the period the Prior Credit Facility was outstanding, the Company was in compliance with all covenants.

The Prior Credit Facility provided for interest rates plus an applicable margin to be determined based on LIBOR or a base rate, at the Company's election. LIBOR borrowings bore interest at LIBOR, plus a margin of 3.00% to 4.00% depending on the utilization level, and the base rate borrowings bore interest at the Reference Rate, as defined in the Prior Credit Facility, plus a margin of 2.00% to 3.00% depending on the utilization level.

This Prior Credit Facility was terminated and settled in full as of December 7, 2018.

Predecessor Debt

Please refer to *Note 14 - Chapter 11 Proceedings and Emergence* for discussion regarding the predecessor credit facility and predecessor senior unsecured notes.

Interest Expense

For the years ended December 31, 2019, 2018, the 2017 Successor Period, and the 2017 Predecessor Period, the Company incurred interest expense of $5.1 million, $2.6 million, $0.8 million, and $5.7 million respectively. The Company capitalized $2.4 million of interest expense during the year ended December 31, 2019. No interest was capitalized for the year ended December 31, 2018, the 2017 Successor Period, or the 2017 Predecessor Period.

NOTE 7 - COMMITMENTS AND CONTINGENCIES

Legal Proceedings

From time to time, the Company is involved in various commercial and regulatory claims, litigation, and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with authoritative accounting guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations. As of the filing date of this report, there were no probable, material pending, or overtly threatened legal actions against the Company of which it is aware.

The Company and the Colorado Department of Public Health and Environment ("CDPHE") agreed to a Compliance Order on Consent (the "COC") resolving the matters addressed by a compliance advisory issued to the Company for certain storage tank facilities located in the Wattenberg Field with respect to applicable air quality regulations. The COC further set forth compliance requirements and criteria for continued operations. The Company adopted procedures and processes to address the monitoring, reporting, and control of air emissions. In order to be in compliance, the Company has incurred approximately $2.1 million from 2017 through December 31, 2019 and expects to incur an immaterial amount of maintenance during 2020 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

In February 2019, the Company was sent a notice of intent to sue ("NOI") letter by WildEarth Guardians ("WEG"), an environmental non-governmental organization, alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The Company is one of seven operators in the Wattenberg Field to receive such an NOI letter from WEG, and these letters appear to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes.

On May 3, 2019, WEG filed a lawsuit against the Company and the other six operators who received the NOI, alleging claims consistent with those contained in the NOI letters. Because the allegations made in the lawsuit are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit, but the Company will vigorously defend against such allegations and will coordinate as much as possible with state and federal permitting authorities to maintain the validity of its current and future air permits for such facilities.

In September 2018, the Company reached a settlement in a case in which it was one of several plaintiffs seeking reimbursement of ad valorem taxes that were assessed by a special metropolitan district in Colorado. Pursuant to that settlement, the Company received a gross reimbursement of ad valorem taxes paid in the amount of $7.4 million. The settlement amount of $5.1 million, net of the Company's associated interest owners' portion, is presented as a reimbursement in the accompanying statements of operations within the severance and ad valorem taxes line item. This net settlement amount will be further reduced to reflect the reimbursement to the State of Colorado of a certain amount of severance tax credits received in connection with ad valorem taxes historically paid by the Company.

Commitments

The purchase agreement to deliver fixed determinable quantities of crude oil to NGL Crude became effective on April 28, 2017. The NGL Crude agreement includes defined volume commitments over an initial seven-year term. Under the terms of the NGL Crude agreement, the Company will be required to make periodic deficiency payments for any shortfalls in delivering minimum volume commitments, which are set in six-month periods beginning in January 2018. There were no minimum volume commitments for the year ending December 31, 2017. During 2018, the average minimum volume commitment was approximately 10,100 barrels per day, and the minimum gross volume commitment increased by approximately 41% from 2018 to 2019 and will increase approximately 3% each year thereafter for the remainder of the contract, to a maximum of approximately 16,000 gross barrels per day. The aggregate financial commitment fee over the remaining term is $81.0 million as of December 31, 2019. Upon notifying NGL Crude at least twelve months prior to the expiration date of the NGL Crude agreement, the Company may elect to extend the term of the new NGL Crude agreement for up to three additional years.

The annual minimum commitment payments under the NGL Crude agreement for the next five years as of December 31, 2019 are presented below (in thousands):

	NGL Crude Commitments (1)
2020	$ 22,474
2021	23,316
2022	24,009
2023	11,200
2024 and thereafter	—
Total	$ 80,999

(1) The above calculation is based on the minimum volume commitment schedule (as defined in the NGL Crude agreement) and applicable differential fees.

Since the commencement of the NGL Crude agreement and through the remainder of the term of the agreement, the Company has not and does not expect to incur any deficiency payments. Refer to *Note 2 - Leases*, for operating lease commitments.

NOTE 8 - STOCK-BASED COMPENSATION

2017 Long Term Incentive Plan

Upon emergence from bankruptcy, the Company adopted a new Long Term Incentive Plan (the “2017 LTIP”), as established by the pre-emergence Board, which allows for the issuance of RSU's, PSU's, and options. On the Effective Date, the Company reserved 2,467,430 shares of the new common stock for issuance under the 2017 LTIP. See below for further discussion of awards granted under the 2017 LTIP.

The Company recorded compensation expense related to the awards granted under the 2017 LTIP as follows (in thousands):

	For the Years Ended December 31,		
	2019	2018	2017 Successor Period
Restricted stock units	$ 5,518	$ 5,140	$ 7,913
Performance stock units	764	621	—
Stock options	604	1,395	3,717
	$ 6,886	$ 7,156	$ 11,630

As of December 31, 2019, unrecognized compensation expense will be amortized through the relevant periods as follows (in thousands):

	Unrecognized Compensation Expense	Final Year of Recognition
Restricted stock units	$ 9,589	2023
Performance stock units	1,714	2021
Stock options	174	2020
	$ 11,477	

Inducement Awards

During the year ended December 31, 2018, the Company granted inducement awards in the form of RSUs separate and distinct from the 2017 LTIP. The total number of inducement awards granted to employees during the year ended December 31, 2018 was 170,613, representing a total fair value of $4.6 million.

Restricted Stock Units

The 2017 LTIP allows for the issuance of RSUs to members of the Board and employees of the Company at the discretion of the Board. Each RSU represents one share of the Company's common stock to be released from restriction upon completion of the vesting period. The awards typically vest in one-third increments over three years. The RSUs are valued at the grant date share price and are recognized as general and administrative expense over the vesting period of the award.

In 2017, the Company granted 63,894 RSUs to non-executive members of the Board, with a fair value of $2.3 million. This grant is intended to cover a three-year period, and the RSUs will vest in equal installments on each of the first three anniversaries. The vested shares will be released upon the earlier of the third anniversary of the grant date, a change of control, or the director's separation from the Company.

The fair value of the RSUs granted from the 2017 LTIP during the years ended December 31, 2019, 2018, and the 2017 Successor Period was $5.9 million, $6.2 million, and $13.4 million, respectively.

A summary of the status and activity of non-vested restricted stock units for the year ended December 31, 2019 is presented below:

	Restricted Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	480,835	$ 30.83
Granted	258,785	$ 22.70
Vested	(143,761)	$ 23.12
Forfeited	(38,042)	$ 25.92
Non-vested, end of year	557,817	$ 26.95

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from operating activities. Excess tax benefits are realized tax benefits from tax deductions for vested restricted stock in excess of the deferred tax asset attributable to stock compensation costs for such restricted stock. The Company recorded no excess tax benefits for the years ended December 31, 2019 and 2018, and 2017 Successor Period.

Performance Stock Units

The 2017 LTIP allows for the issuance of PSUs to employees at the sole discretion of the Board. The number of shares of the Company's common stock that may be issued to settle PSUs range from zero to two times the number of PSUs awarded. The PSUs vest in their entirety at the end of the three-year performance period. The total number of PSUs granted is evenly split between two performance criteria. The first criterion is based on a comparison of the Company's absolute and relative total shareholder return ("TSR") for the performance period compared with the TSRs of a group of peer companies for the same performance period. The TSR for the Company and each of the peer companies is determined by dividing (A)(i) the volume-weighted average share price for the last 30 trading days of the performance period, minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The second criterion is based on the Company's average annual return on capital employed ("ROCE") for each year during the three-year performance period. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period. Because these awards depend on a combination of performance-based and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected ROCE performance.

The fair value of the PSUs was measured at the grant date. The portion of the PSUs tied to the TSR required a stochastic process method using a Brownian Motion simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's TSRs, the Company could not predict with certainty the path its stock price or the stock prices of its peers would take over the performance period. By using a stochastic simulation, the Company created multiple prospective stock pathways, statistically analyzed these simulations, and ultimately made inferences regarding the most likely path the stock price would take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Brownian Motion Model, was deemed an appropriate method by which to determine the fair value of the portion of the PSUs tied to the TSR. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the performance period, as well as the volatilities for each of the Company's peers.

The following table presents the assumptions used to determine the fair value of the TSR portion of the PSUs:

	For the Years Ended December 31,	
	2019	2018
Expected term (in years)	3	3
Risk-free interest rate	2.26 %	2.76 %
Expected daily volatility	2.6 %	2.6 %

The fair value of the PSUs granted during 2019 and 2018 was $2.3 million and $1.8 million, respectively.

A summary of the status and activity of performance stock units for the year ended December 31, 2019 is presented below:

	Performance Stock Units[(1)]	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	53,689	$ 29.92
Granted	102,379	$ 22.15
Vested	(2,598)	$ 23.55
Forfeited	—	$ —
Non-vested, end of year	153,470	$ 24.74

(1) The number of awards assumes that the associated performance condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

Stock Options

The 2017 LTIP allows for the issuance of stock options to the Company's employees at the sole discretion of the Board. Options expire ten years from the grant date unless otherwise determined by the Board. Compensation expense on the stock options is recognized as general and administrative expense over the vesting period of the award.

There were no stock options granted during 2019 and 2018. The fair value of the stock options granted during the 2017 Successor Period was $6.8 million.

Stock options were valued using a Black-Scholes Model where expected volatility is based on an average historical volatility of a peer group selected by management over a period consistent with the expected life assumption on the grant date, the risk-free rate of return is based on the U.S. Treasury constant maturity yield on the grant date with a remaining term equal to the expected term of the awards, and the Company's expected life of stock option awards is derived from the midpoint of the average vesting time and contractual term of the awards.

	For the Year Ended December 31, 2017
Expected term (years)	6.0
Risk-free interest rate	1.96 %
Expected volatility	52.1 %
Expected dividends	— %

A summary of the status and activity of non-vested stock options for the year ended December 31, 2019 is presented below:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of year	132,809	$ 34.36		
Granted	—	$ —		
Exercised	—	$ —		
Forfeited	(32,095)	$ 34.36		
Outstanding, end of year	100,714	$ 34.36	6.7	$ —
Options outstanding and exercisable	70,077	$ 34.36	6.4	$ —

Predecessor Long Term Incentive Plan

The Company's Predecessor Long Term Incentive Plan (the "Predecessor Plan") had different forms of equity issuances allowed under it, including restricted stock, performance stock units, and long term incentive plan units ("predecessor awards"). Upon emergence from bankruptcy, the Company's predecessor awards were canceled.

The Company recorded compensation expense related to the awards granted under the Predecessor Plan as follows (in thousands):

	2017 Predecessor Period
Restricted stock units	$ 1,267
Performance stock units	451
Plan units	398
	$ 2,116

NOTE 9 - INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax basis of assets and liabilities and amounts reported in the Company’s balance sheets. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liabilities determines the periodic provision for deferred taxes.

The provision for income taxes consists of the following (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Current tax benefit				
Federal	$ —	$ —	$ 376	$ —
State	—	—	—	—
Deferred tax benefit	—	—	—	—
Total income tax benefit	$ —	$ —	$ 376	$ —

Temporary differences between the financial statement carrying amounts and tax basis of assets and liabilities that give rise to the net deferred tax asset (liability) result from the following components (in thousands):

	As of December 31,	
	2019	2018
Deferred tax liabilities:		
Oil and gas properties	$ 79,187	$ 52,006
Derivative instruments	—	8,527
Right-of-use assets	9,508	—
Total deferred tax liabilities	88,695	60,533
Deferred tax assets:		
Federal and state tax net operating loss carryforward	139,546	137,567
Derivative instruments	1,062	—
Reclamation costs	6,881	7,251
Stock compensation	2,209	1,635
Accrued compensation	—	1,308
Inventory	1,577	1,577
Lease liability	9,673	—
Other long-term assets	300	271
Total deferred tax assets	161,248	149,609
Less: Valuation allowance	72,553	89,076
Total deferred tax assets after valuation allowance	88,695	60,533
Total non-current net deferred tax asset (liability)	$ —	$ —

The Company has $582.8 million and $577.6 million of net operating loss carryovers for federal income tax purposes as of December 31, 2019 and 2018, respectively. Federal net operating loss carryforwards incurred prior to January 1, 2018 of $470.3 million will begin to expire in 2036. Federal net operating loss carryforwards incurred after December 31, 2017 of $112.5 million have no expiration and can only be used to offset 80% of taxable income when utilized. The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. As a result of the Company's analysis, it was concluded that as of December 31, 2019 and 2018 a valuation allowance should be established against the Company's deferred tax asset. The Company recorded a valuation allowance as of December 31, 2019 and 2018 of $72.6 million and $89.1 million, respectively, on its deferred tax assets. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate of 21% to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, rate changes, and other permanent differences, as follows (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Federal statutory tax (expense) benefit by applying the statutory rate	$ 14,084	$ 35,319	$ 1,889	$ (931)
Decrease (increase) in tax resulting from:				
State tax expense net of federal benefit	2,537	6,556	172	(85)
Prior year true-up	(579)	(458)	—	(7,572)
Stock compensation	197	854	—	(1,773)
Permanent differences	128	61	(715)	(35,273)
Rate change	—	(421)	(73,956)	—
NOL Adjustment	—	5,973	—	—
Other	156	—	(642)	—
Valuation allowance	(16,523)	(47,884)	73,628	45,634
Total income tax benefit	$ —	$ —	$ 376	$ —

There was no deferred income tax benefit or expense in the accompanying statements of operations. The valuation allowance decreased by $16.5 million to $72.6 million in 2019 when compared to the same period in 2018. The Company's net income decreased between the comparable periods causing the federal tax benefit to decrease.

During the year ended December 31, 2018, the decrease in tax rate was primarily due to placing a valuation allowance against net deferred tax assets. There was no deferred income tax benefit or expense in the accompanying statements of operations. The valuation allowance decreased to $89.1 million in 2018 due to improvement of operational results. Net operating losses are inherently subject to changes in ownership. The net operating loss adjustment was derived from the write-off of the Company's Mid-Continent tax attributes upon the sale of those assets.

During the year ended December 31, 2017, the decrease in tax rate was primarily due to the enactment of the Tax Cuts and Jobs Act (“Tax Act”). There was $0.4 million of current income tax benefits in the accompanying statements of operations due to the AMT payments being refunded as prescribed in the Tax Act. The valuation allowance decreased to $137.0 million in 2017 due to decreased tax rate as mandated by the Tax Act.

The Company had no unrecognized tax benefits as of December 31, 2019, 2018, and 2017. The tax returns for 2018, 2017, and 2016 are still subject to audit by the Internal Revenue Service.

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for future costs to abandon its oil and gas properties. The fair value of the asset retirement obligation is recorded as a liability when incurred, which is typically at the time the asset is acquired or placed in service. There is a corresponding increase to the carrying value of the asset, which is included in the proved properties line item in the accompanying balance sheets. The Company depletes the amount added to proved properties and recognizes expense in connection with accretion of the discounted liability over the remaining estimated economic lives of the properties.

The Company’s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimated costs to abandon the wells, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred.

A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

	For the Years Ended December 31,	
	2019	2018
Balance, beginning of year	$ 29,405	$ 38,262
Additional liabilities incurred	228	373
Accretion expense	1,467	1,831
Liabilities settled	(2,443)	(1,627)
Revisions to estimate	(749)	1,490
Sold properties	—	(10,924)
Balance, end of year	$ 27,908	$ 29,405

Revisions to the liability could occur due to changes in the estimated economic lives, abandonment costs of the wells, inflation rates, credit-adjusted risk-free rates, along with newly enacted regulatory requirements. Revisions to estimates for the year ended December 31, 2019 were primarily a result of decreased abandonment costs. Revisions to estimates for the year ended December 31, 2018 were primarily a result of an increase in the credit-adjusted risk-free rate applied at year-end and an increase in the inflation rate on wells that had an asset retirement obligation as of the beginning of the year, offset by a slight decrease in abandonment costs.

NOTE 11 - FAIR VALUE MEASUREMENTS

The Company follows fair value measurement authoritative guidance, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities

Level 2: Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3: Significant inputs to the valuation model are unobservable

Financial and non-financial assets and liabilities are to be 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 and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables present the Company’s financial and non-financial assets and liabilities that were accounted for at fair value as of December 31, 2019 and 2018 and their classification within the fair value hierarchy (in thousands):

	As of December 31, 2019		
	Level 1	Level 2	Level 3
Derivative assets(1)	$ —	$ 3,005	$ —
Derivative liabilities(1)	$ —	$ 7,311	$ —
Asset retirement obligations(2)	$ —	$ —	$ (749)

	As of December 31, 2018		
	Level 1	Level 2	Level 3
Derivative assets(1)	$ —	$ 38,272	$ —
Derivative liabilities(1)	$ —	$ 183	$ —
Asset retirement obligations(2)	$ —	$ —	$ 1,490

(1) Represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) Represents the revision to estimates of the asset retirement obligation, which is a non-financial liability that is measured at fair value on a nonrecurring basis. Please refer to the *Asset Retirement Obligation* section below for additional discussion.

Derivatives

Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company’s commodity swaps and collars were validated by observable transactions for the same or similar commodity options using the NYMEX futures index and were designated as Level 2 within the valuation hierarchy.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. Depending on the availability of data, the Company uses Level 3 inputs and either the income valuation technique, which converts future amounts to a single present value amount to measure the fair value of proved properties through an application of risk-adjusted discount rates and price forecasts selected by the Company’s management, or the market valuation approach. The calculation of the risk-adjusted discount rate is a significant management estimate based on the best information available. Management believes that the risk-adjusted discount rate is representative of current market conditions and reflects the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on the Company's internal budgeting model derived from the NYMEX strip pricing, adjusted for management estimates and basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If a relevant estimated selling price is not available, the Company utilizes the income valuation technique discussed above. There were no oil and gas property impairments during the years ended December 31, 2019 and 2018.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be fully recoverable. To measure the fair value of unproved properties, the Company uses Level 3 inputs and the income valuation technique, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, remaining lease life, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If a relevant estimated selling price is not available, the Company uses the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. During 2019, the Company incurred $11.2 million in abandonment and impairment of unproved properties due to reassessment of estimated probable and possible reserve values and the expiration of non-core leases. During 2018, the

Company incurred $5.3 million in abandonment and impairment of unproved properties due to the expiration of non-core leases.

Asset Retirement Obligation

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Upon completion of wells, the Company records an asset retirement obligation at fair value using Level 3 assumptions. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. The Company had revisions of estimates resulting in a decrease of $0.7 million and an increase of $1.5 million of asset retirement obligations recorded at fair value as of December 31, 2019 and 2018, respectively.

NOTE 12 - DERIVATIVES

The Company enters into commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company’s derivatives include swaps, collars, and puts for oil and natural gas, and none of the derivative instruments qualify as having hedging relationships.

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap strike price, the Company receives the difference between the index price and the agreed upon swap strike price. If the index price is higher than the swap strike price, the Company pays the difference.

A put gives the owner the right to sell the underlying commodity at a set price over the term of the contract. If the index settlement price is higher than the put fixed price, the put will expire worthless. If the settlement price is lower than the put fixed price, the Company will exercise the put and receive the difference between the settlement price and the put fixed price.

A cashless collar arrangement establishes a floor and ceiling price on future oil and gas production. When the settlement price is above the ceiling price, the Company pays the difference between the settlement price and the ceiling price. When the settlement price is below the floor price, the Company receives the difference between the settlement price and floor price. In the event that the settlement price is between the ceiling and the floor, no payment or receipt occurs.

A basis swap arrangement guarantees a price differential from a specified delivery point to an agreed upon reference point. The Company receives the difference between the price differential and the stated terms, if the price differential is greater than the stated terms. The Company pays the difference between the price differential and the stated terms, if the stated terms are greater than the price differential.

As of December 31, 2019, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG Basis)		Natural Gas (CIG)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu
1Q20								
Cashless Collar	5,000	$55.00/$62.88	—	—	—	—	—	—
Swap	4,500	$60.69	20,000	$2.63	20,000	$0.56	2,500	$2.40
2Q20								
Cashless Collar	7,500	$54.00/$61.01	—	—	—	—	—	—
Swap	1,500	$54.98	10,000	$2.61	20,000	$0.56	—	—
3Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,000	$53.60	—	—	20,000	$0.56	—	—
4Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,000	$53.60	—	—	20,000	$0.56	—	—
1Q21								
Cashless Collar	2,000	$50.50/$55.19	—	—	—	—	—	—
Swap	3,500	$53.89	—	—	—	—	—	—
2Q21								
Cashless Collar	500	$52.00/$55.00	—	—	—	—	—	—
Swap	2,000	$53.35	—	—	—	—	—	—
3Q21								
Swap	1,000	$54.87	—	—	—	—	—	—

As of the filing date of this report, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (CIG Basis)		Natural Gas (CIG)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Price per MMBtu
1Q20								
Cashless Collar	5,000	$55.00/$62.88	—	—	—	—	—	—
Swap	4,500	$60.69	20,000	$2.63	26,593	$0.55	2,500	$2.40
2Q20								
Cashless Collar	7,500	$54.00/$61.01	—	—	—	—	—	—
Swap	1,500	$54.98	10,000	$2.61	30,000	$0.54	—	—
3Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,500	$54.12	—	—	30,000	$0.54	—	—
4Q20								
Cashless Collar	6,000	$52.67/$58.40	—	—	—	—	—	—
Swap	3,500	$54.12	—	—	30,000	$0.54	—	—
1Q21								
Cashless Collar	2,000	$50.50/$55.19	—	—	—	—	—	—
Swap	5,000	$54.48	—	—	—	—	—	—
2Q21								
Cashless Collar	500	$52.00/$55.00	—	—	—	—	—	—
Swap	4,000	$54.13	—	—	—	—	—	—
3Q21								
Swap	2,500	$54.45	—	—	—	—	—	—
4Q21								
Swap	1,000	$55.20	—	—	—	—	—	—

Derivative Assets and Liabilities Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The following table contains a summary of all the Company’s derivative positions reported on the accompanying balance sheets as of December 31, 2019 and 2018 (in thousands):

	As of December 31,	
	2019	2018
Derivative Assets:		
Commodity contracts - current	$ 2,884	$ 34,408
Commodity contracts - noncurrent	121	3,864
Derivative Liabilities:		
Commodity contracts - current	(6,390)	(183)
Commodity contracts - long-term	(921)	—
Total derivative assets (liabilities), net	$ (4,306)	$ 38,089

The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations for the periods below (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Derivative cash settlement gain (loss):				
Oil contracts	$ 1,185	$ (17,700)	$ (1,486)	$ —
Gas contracts	506	(460)	22	—
Total derivative cash settlement gain (loss)(1)	1,691	(18,160)	(1,464)	—
Change in fair value gain (loss)	(38,836)	48,431	(13,901)	—
Total derivative gain (loss)(1)	$ (37,145)	$ 30,271	$ (15,365)	$ —

(1) Total derivative gain (loss) and total derivative cash settlement gain (loss) for each of the periods presented above is reported in the derivative (gain) loss line item and derivative cash settlements line item in the accompanying statements of cash flows, within the cash flows from operating activities.

NOTE 13 - EARNINGS PER SHARE

The Company issues RSUs, which represent the right to receive, upon vesting, one share of the Company's common stock. The number of potentially dilutive shares related to RSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the vesting period. The Company issues PSUs, which represent the right to receive, upon settlement of the PSUs, a number of shares of the Company's common stock that range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the performance period applicable to such PSUs. The Company issued stock options and warrants, which both represent the right to purchase the Company's common stock at a specified price. The number of potentially dilutive shares related to the stock options is based on the number of shares, if any, that would be exercised at the end of the respective reporting period, assuming that date was the end of such stock options' term. The number of potentially dilutive shares related to the warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period.

Please refer to *Note* 8 - *Stock-Based Compensation* for additional discussion.

The Company uses the treasury stock method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

	Successor		
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017
Net income (loss)	$ 67,067	$ 168,186	$ (5,020)
Basic net income (loss) per common share	$ 3.25	$ 8.20	$ (0.25)
Diluted net income (loss) per common share	$ 3.24	$ 8.16	$ (0.25)
Weighted-average shares outstanding - basic	20,612	20,507	20,427
Add: dilutive effect of contingent stock awards	69	96	—
Weighted-average shares outstanding - diluted	20,681	20,603	20,427

There were 269,208 and 170,755 shares that were anti-dilutive for the years ended December 31, 2019 and 2018, respectively. The exercise price of the Company's warrants was in excess of the Company's stock price; therefore, they were excluded from the earnings per share calculation. The Company was in a net loss position for the 2017 Successor Period, which made the 375,123 potentially dilutive shares anti-dilutive.

The Predecessor Company issued shares of restricted stock, which entitled the holders to receive non-forfeitable dividends if and when the Predecessor Company was to declare a dividend before vesting, thus making the awards participating securities. The awards are included in the calculation of earnings per share under the two-class method. The two-class method allocates earnings for the period between common shareholders and unvested participating shareholders and losses to common shareholders only.

The Predecessor Company issued units, which represented the right to receive, upon vesting, shares of the Predecessor Company's common stock on a one-to-one basis up to a share price of $26. In the event the price of the Company's common stock were to exceed $26, the number of shares distributed would be adjusted downward so that the shares distributed would represent a value equivalent to $26 per share.

The Predecessor Company issued PSUs, which represented the right to receive, upon settlement of the PSUs, a number of shares of the Predecessor Company’s common stock that range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the measurement period applicable to such PSUs. Please refer to *Note 8 - Stock-Based Compensation* for additional discussion.

The following table sets forth the calculation of income per basic and diluted shares from net income for the Predecessor Period ended April 28, 2017 (in thousands, except per share amounts):

	Predecessor
	January 1, 2017 through April 28, 2017
Net income	$ 2,660
Less: undistributed income to unvested restricted stock	120
Undistributed income to common shareholders	$ 2,540
Basic net income per common share	$ 0.05
Diluted net income per common share	$ 0.05
Weighted-average shares outstanding - basic	49,559
Add: dilutive effect of contingent PSUs	1,412
Weighted-average shares outstanding - diluted	50,971

The 2017 Predecessor Period had 258,126 anti-dilutive shares.

NOTE 14 - CHAPTER 11 PROCEEDINGS AND EMERGENCE

On December 23, 2016, Bonanza Creek Energy, Inc. and its subsidiaries entered into a Restructuring Support Agreement with (i) holders of approximately 51% in aggregate principal amount of the Company's 5.75% Senior Notes due 2023 (“5.75% Senior Notes”) and 6.75% Senior Notes due 2021 (“6.75% Senior Notes”), collectively (the “Senior Notes”) and (ii) NGL Energy Partners, LP and NGL Crude Logistics, LLC.

On January 4, 2017, the Company filed voluntary petitions under Chapter 11 of the United States Bankruptcy Code. The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017.

Reorganization

On the Effective Date, the Senior Notes and existing common shares of the Company (“existing common shares”) were canceled, and the reorganized Company issued: (i) new common stock; (ii) three year warrants (“warrants”); and (iii) rights (the “subscription rights”) to acquire the new common shares offered in connection with the rights offering (the “rights offering”).

- the Senior Notes aggregate principal amount of $800.0 million, plus $14.9 million of accrued and unpaid pre-petition interest and $51.2 million of prepayment premiums was settled for 46.6% or 9,481,610 shares of the Company's new common stock;
- the Company issued 803,083 or 3.9% of the new common stock to holders of our existing common stock, of which 1.75% was for the ad hoc equity committee settlement in exchange for $7.5 million, on terms equivalent to the rights offering;
- the Company issued 10,071,378 shares of new common stock in exchange for $200.0 million relating to the rights offering;
- the Company issued 1,650,510 of warrants entitling their holders upon exercise thereof, on a pro rata basis, to 7.5% of the total outstanding new common shares at a per share price of $71.23 per warrant; and
- the Company reserved 2,467,430 shares of the new common stock for issuance under its 2017 Long Term Incentive Plan (“LTIP”).

Pursuant to the terms of the approved Plan the following transactions were completed on the Effective Date;

- the Company paid Silo Energy, LLC (“Silo”) the contract settlement amount of $7.2 million in full;
- with respect to the predecessor credit facility, dated March 29, 2011 (the “predecessor credit facility”), principal, accrued interest, and fees of $193.7 million were paid in full;
- the Company paid $1.6 million for the 2016 Short Term Incentive Plan (“2016 STIP”) to various employees;
- the Company funded an escrow account in the amount of $17.2 million for professional service fees attributable to its advisers;
- the Company paid $13.8 million for professional services attributable to advisers of third parties involved in the bankruptcy proceedings;
- the Company emerged with cash on hand of $70.2 million for operations; and
- the Company amended its articles of incorporation and bylaws for the authorization of the new common stock.

As confirmed in the Plan, the Company terminated its purchase agreement with Silo on February 1, 2017, and entered into a settlement agreement that allowed Silo to: (i) retain the $5.0 million adequate assurance deposit maintained, (ii) retain the Company's $8.7 million crude oil revenue receivable due to the Company for December 2016 production, and (iii) receive additional cash payment of $7.2 million, which was paid on the Effective Date.

NOTE 15 - FRESH-START ACCOUNTING

Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh-start accounting, pursuant to FASB ASC *852, Reorganizations*, and applied the provisions thereof to its financial statements. The Company qualified for fresh-start accounting because: (i) the holders of existing voting shares of the Predecessor Company received less than 50% of the voting shares of the Successor Company; and (ii) the reorganization value of the Company's assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. The Company applied fresh-start accounting as of April 28, 2017, when it emerged from bankruptcy protection. Adopting fresh-start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit as of the fresh-start reporting date. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares of the Successor Company caused a related change of control of the Company under ASC 852.

Reorganization Value

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

The Company's reorganization value is derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity’s long-term debt, other interest bearing liabilities, and shareholders’ equity, less total cash and cash equivalents. In support of the Plan, the enterprise value of the Successor Company was estimated and approved by the Bankruptcy Court to be in the range of $570.0 million to $680.0 million. Based on the estimates and assumptions used in determining the enterprise value, as further discussed below, the Company estimated the enterprise value to be approximately $643.0 million. This valuation analysis was prepared with the assistance of an independent third-party consultant utilizing reserve information prepared by the Company's internal reserve engineers, internal development plans and schedules, other internal financial information and projections and the application of standard valuation techniques including risked net asset value analysis and comparable public company metrics.

The Company's principal assets are its oil and gas properties. The Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets segregated into geographic regions. The computations were based on market conditions and reserves in place as of the Effective Date. Discounted cash flow models were generated using the estimated future revenues and development and operating costs for all developed wells and undeveloped locations comprising our proved reserves. The proved locations were limited to wells expected to be drilled in the Company's five year plan. Future cash flows before application of risk factors were estimated by using the New York Mercantile Exchange five year forward prices for West Texas Intermediate oil and Henry Hub natural gas with inflation adjustments applied to periods beyond five years. The prices were further adjusted for typical differentials realized by the Company for the location and product quality. Wattenberg Field oil differential estimates were based on the new NGL Crude purchase agreement that was confirmed as part of the Plan. Development costs were based on recent bids received by the Company and the operating costs were based on actual costs, and both were adjusted by the same inflation rate used for revenues. The discounted cash flow models also included estimates not typically included in proved reserves, such as an industry standard general and administrative expense and income tax expense. Due to the limited drilling plans that we had in place, proved undeveloped locations were risked within industry standards.

The risk-adjusted after-tax cash flows were discounted at a rate of 11.0%. This rate was determined from a weighted-average cost of capital computation, which utilized a blended expected cost of debt and expected returns on equity for similar industry participants.

From this analysis the Company concluded the fair value of its proved, probable, and possible reserves was $397.3 million, $146.8 million, and $31.7 million, respectively, as of the Effective Date. The Company also reviewed its undeveloped leasehold acreage and determined that the fair value of its probable and possible reserves appropriately capture the fair value of its undeveloped leasehold acreage.

The Company performed an analysis of its RMI assets using a replacement cost method which estimated the assets' replacement cost (for new assets), less any depreciation, physical deterioration, or obsolescence, resulting in a fair value of $103.1 million.

The Company follows the lower of cost or net realizable value when valuing inventory of oilfield equipment. The valuation of the inventory of oilfield equipment as of the Effective Date did not yield a material difference from the Company's carrying value immediately prior to emergence from bankruptcy; as such, there was no valuation adjustment recorded.

The valuation of the Company's other property and equipment as of the Effective Date did not yield a material difference from the Predecessor Company's net book value; as such there was no valuation adjustment recorded.

Our liabilities on the Effective Date include working capital liabilities and asset retirement obligations. Our working capital liabilities are ordinary course obligations, and their carrying amounts approximate their fair values. The asset retirement obligation was reset using a revised credit-adjusted risk-free rate and known attributes as of the Effective Date, resulting in a $29.1 million obligation.

In conjunction with the Company's emergence from bankruptcy, the Company issued 1,650,510 warrants to existing equity holders. The fair value of $4.1 million was estimated using a Black-Scholes pricing model. The model used the following assumptions; an expected volatility of 40%, a risk-free interest rate of 1.44%, a stock price of $34.36, a strike price of $71.23, and an expiration date of 3 years.

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

Enterprise Value	$	642,999
Plus: Cash and cash equivalents		70,183
Less: Interest bearing liabilities		(29,061)
Less: Fair value of warrants		(4,081)
Fair value of Successor common stock	$	680,040
Shares outstanding at April 28, 2017		20,356
Per share value	$	33.41

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

Enterprise Value	$	642,999
Plus: Cash and cash equivalents		70,183
Plus: Working capital liabilities		63,871
Plus: Other long-term liabilities		17,919
Reorganization value of Successor assets	$	794,972

Successor Condensed Consolidated Balance Sheet

The adjustments set forth in the following condensed consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column “Reorganization Adjustments”) as well as estimated fair value adjustments as a result of the adoption of fresh-start accounting (reflected in the column “Fresh-Start Adjustments”). The explanatory notes highlight methods used to determine estimated fair values or other amounts of assets and liabilities, as well as significant assumptions.

ASSETS	Predecessor Company		Reorganization Adjustments			Fresh-Start Adjustments			Successor Company	
	(in thousands, except share amounts)									
Current Assets:										
Cash and cash equivalents	$	96,286	$	(26,103)	(1)	$	—			70,183
Accounts receivable:										
Oil and gas sales		24,876		—			—			24,876
Joint interest and other		3,028		—			—			3,028
Prepaid expenses and other		4,952		—			—			4,952
Inventory of oilfield equipment		4,218		—			—			4,218
Total current assets		133,360		(26,103)			—			107,257
Property and equipment (successful efforts method):										
Proved properties		2,531,834		—			(2,031,373)	(6)		500,461
Less: accumulated depreciation, depletion and amortization		(1,720,736)		—			1,720,736	(6)		—
Total proved properties, net		811,098		—			(310,637)			500,461
Unproved properties		163,781		—			14,679	(6)		178,460
Wells in progress		18,002		—			(18,002)	(7)		—
Other property and equipment, net		6,056		—			—			6,056
Total property and equipment, net		998,937		—			(313,960)			684,977
Other noncurrent assets		2,738		—			—			2,738
Total assets	$	1,135,035	$	(26,103)		$	(313,960)		$	794,972
LIABILITIES AND STOCKHOLDERS'S EQUITY										
Current liabilities:										
Accounts payable and accrued expenses	$	72,635	$	(33,701)	(2)	$	—		$	38,934
Oil and gas revenue distribution payable		24,937		—			—			24,937
Predecessor credit facility - current portion		191,667		(191,667)	(3)		—			—
Total current liabilities		289,239		(225,368)			—			63,871
Long-term liabilities:										
Ad valorem taxes		17,919		—			—			17,919
Asset retirement obligations for oil and gas properties		31,660		—			(2,599)	(8)		29,061
Liabilities subject to compromise		873,292		(873,292)	(4)		—			—
Total liabilities		1,212,110		(1,098,660)			(2,599)			110,851
Stockholders' equity:										
Predecessor preferred stock		—		—			—			—
Predecessor common stock		49		—			(49)	(9)		—
Additional paid in capital		816,679		—			(816,679)	(9)		—
Successor common stock		—		204	(5)		—			204
Successor warrants		—		4,081	(5)		—			4,081
Additional paid-in capital		—		679,836	(5)		—			679,836
Retained deficit		(893,803)		388,436	(4)		505,367	(10)		—
Total stockholders' equity		(77,075)		1,072,557			(311,361)			684,121
Total liabilities and stockholders' equity	$	1,135,035	$	(26,103)		$	(313,960)		$	794,972

Reorganization Adjustments

(1) The following table reflects the net cash payments made upon emergence on the Effective Date (in thousands):

Sources:		
Proceeds from rights offering	$	200,000
Proceeds from ad hoc equity committee		7,500
Total sources	$	207,500
Uses and transfers:		
Payment on predecessor credit facility (principal, interest and fees)	$	(193,729)
Payment and funding of escrow account related to professional fees		(17,193)
Payment of professional fees and other		(13,831)
Payment of Silo contract settlement and other		(7,228)
Payment of remaining 2016 STIP		(1,622)
Total uses and transfers	$	(233,603)
Total net sources, uses and transfers	$	(26,103)

(2) The following table shows the decrease of accounts payable and accrued liabilities attributable to reorganization items settled or paid upon emergence (in thousands):

Accounts payable and accrued expenses:		
Accrued 2016 STIP payment	$	(1,574)
Escrow account funding		(17,193)
Professional fees and other		(13,831)
Accrued unpaid interest on predecessor credit facility		(1,103)
Total accounts payable and accrued expenses settled	$	(33,701)

(3) Represents the payment in full of the predecessor credit facility on the Effective Date.

(4) On the Effective Date, the obligations of the Company with respect to the Senior Notes were canceled. Liabilities subject to compromise were settled as follows in accordance with the Plan (in thousands):

Senior Notes	$	800,000
Accrued interest on Senior Notes (pre-petition)		14,879
Make-whole payment on Senior Notes		51,185
Silo contract settlement accrual		7,228
Total liabilities subject to compromise of the predecessor		873,292
Rights offering		200,000
Fair value of equity issued to creditors, excluding equity issued to existing equity holders		(653,212)
Payment of Silo contract settlement		(7,228)
Gain on settlement of liabilities subject to compromise		412,852
Payment on predecessor credit facility fees and remaining unaccrued 2016 STIP		(1,007)
Total reorganization items at emergence		411,845
Issuance of warrants to existing shareholders		(4,081)
Proceeds from ad hoc equity committee		7,500
Issuance of shares to existing shareholders		(26,828)
Total reorganization adjustments to retained deficit	$	388,436

(5) Represents the fair value of 20,356,071 shares of new common stock and 1,650,510 warrants issued upon emergence from bankruptcy on the Effective Date.

Fresh-Start Adjustments

(6) Fair value adjustments to proved and unproved oil and natural gas properties. A combination of the market and income approach were utilized to perform valuations. Included in this line items were adjustments to the fully-owned subsidiary, Rocky Mountain Infrastructure, LLC. Lastly, the accumulated depreciation was reset to zero in accordance with fresh-start accounting.

(7) Represents the reset of wells in progress with fair valuation of the associated reserves in proved property.

(8) Upon application of fresh-start accounting and due to the Company's emergence with no debt, the Company revalued its asset retirement obligations based upon comparable companies' credit-adjusted risk-free rates in accordance with *ASC 410 - Asset Retirement and Environmental Obligations.*

(9) Cancellation of Predecessor Company's common stock and additional paid-in capital.

(10) Adjustment to reset retained deficit to zero.

Reorganization Items, Net

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

Gain on settlement of liabilities subject to compromise	$	412,852
Payment on predecessor credit facility fees and remaining unaccrued 2016 STIP		(1,007)
Fresh-start valuation adjustments		(311,361)
Legal and professional fees and expenses		(34,335)
Write-off of debt issuance and premium costs		(6,156)
Make-whole payment on Senior Notes		(51,185)
Total reorganization items, net	$	8,808

NOTE 16 - DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The Company's oil and natural gas activities are located entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2019	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Acquisition[1]	$ 12,901	$ 2,861	$ 5,383	$ 445
Development[2][3]	209,535	304,197	106,449	10,780
Exploration	796	294	3,671	769
Total	$ 223,232	$ 307,352	$ 115,503	$ 11,994

(1) Acquisition costs for unproved properties for the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period were $4.2 million, $2.5 million, $5.4 million, and $0.4 million, respectively. There were $8.7 million and $0.4 million in acquisition costs for proved properties for the years ended December 31, 2019 and 2018, respectively, and no acquisition costs for proved properties for the 2017 Successor Period and the 2017 Predecessor Period.

(2) Development costs include workover costs of $1.4 million, $5.6 million, $4.3 million, and $1.8 million charged to lease operating expense for the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period, respectively.

(3) Includes amounts relating to asset retirement obligations of $(0.9) million, $(9.0) million, $8.3 million, and $3.1 million, for the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period, respectively.

Suspended Well Costs

The Company did not incur any exploratory well costs during the years ended December 31, 2019 and 2018, the 2017 Successor Period, and the 2017 Predecessor Period.

Reserves

The proved reserve estimates at December 31, 2019, 2018, and 2017 were prepared by NSAI, our third party independent reserve engineers. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

All of the Company’s oil, natural gas liquids, and natural gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil, natural gas liquids, and natural gas reserves for the years ended December 31, 2019, 2018, and 2017 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)
Balance-December 31, 2016	50,096	138,045	17,547
Extensions, discoveries and infills(1)	8,470	22,212	3,376
Production	(3,081)	(9,010)	(1,136)
Revisions to previous estimates(3)	(2,557)	6,422	3,028
Balance-December 31, 2017	52,928	157,669	22,815
Extensions, discoveries and infills(1)	18,390	31,471	5,197
Production	(3,841)	(8,567)	(1,140)
Sales of minerals in place	(6,236)	(20,534)	(1,499)
Removed from capital program(2)	(1,442)	(3,246)	(544)
Revisions to previous estimates(3)	4,555	8,219	101
Balance-December 31, 2018	64,354	165,012	24,930
Extensions, discoveries and infills(1)	8,825	20,604	3,123
Production	(5,136)	(11,967)	(1,431)
Sales of minerals in place	(52)	(110)	(18)
Removed from capital program(2)	(4,926)	(11,508)	(1,862)
Purchases of minerals in place	303	627	102
Revisions to previous estimates(3)	1,045	49,542	(2,683)
Balance-December 31, 2019	64,413	212,200	22,161
Proved developed reserves:			
December 31, 2017	25,785	92,718	12,702
December 31, 2018	23,725	79,630	11,703
December 31, 2019	25,397	105,840	11,566
Proved undeveloped reserves:			
December 31, 2017	27,143	64,951	10,113
December 31, 2018	40,629	85,382	13,227
December 31, 2019	39,016	106,360	10,595

(1) During the years ended December 31, 2019, 2018, and 2017, horizontal development in the Wattenberg Field resulted in additions in extensions, discoveries, and infills of 15.4 MMBoe, 28.8 MMBoe, and 15.5 MMBoe, respectively.

(2) During the years ended December 31, 2019 2018, and 2017, proved undeveloped reserves were reduced by 8.7 MMBoe, 2.5 MMBoe, and 7.6 MMBoe respectively, due to the removal of proved undeveloped locations from our five-year drilling program.

(3) As of December 31, 2019, the Company revised its proved reserves upward by 6.6 MMboe. The commodity prices at December 31, 2019 decreased to $55.85 per Bbl WTI and $2.58 per MMBtu HH from $65.56 per Bbl WTI and $3.10 per MMBtu HH at December 31, 2018, resulting in a negative revision of 1.4 MMBoe, offset by 8.1 MMBoe in positive engineering revision.

As of December 31, 2018, the Company revised its proved reserves upward by 6.0 MMBoe. The commodity prices at December 31, 2018 increased to $65.56 per Bbl WTI and $3.10 per MMBtu HH from $51.34 per Bbl WTI and $2.98 per MMBtu HH at December 31, 2017, resulting in positive revisions of 2.3 MMBoe. In addition, lower operating cost estimates resulted in positive reserve adjustments of 1.5 MMBoe. There were net positive engineering revisions of 2.2 MMBoe.

As of December 31, 2017, the Company revised its proved reserves upward by 1.5 MMBoe. The commodity prices at December 31, 2017 increased to $51.34 per Bbl WTI and $2.98 per MMBtu HH from $42.75 per Bbl WTI and $2.48 per MMBtu HH at December 31, 2016, resulting in positive revisions of 5.4 MMBoe. In addition, lower operating cost estimates resulted in positive reserve adjustments (net of price increases) of 1.7 MMBoe, of which 1.4 MMBoe relate to operations in the Wattenberg Field. The Company also had positive other engineering revisions of 2.0 MMBoe, offset by PUD demotions of 7.6 MMBoe.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with accounting authoritative guidance. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on current costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits, and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of the Company's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	For the Years Ended December 31,		
	2019	2018	2017
Future cash flows	$ 3,827,009	$ 4,742,180	$ 3,307,868
Future production costs	(1,029,140)	(1,585,032)	(1,490,091)
Future development costs	(850,327)	(925,640)	(622,344)
Future income tax expense	—	—	—
Future net cash flows	1,947,542	2,231,508	1,195,433
10% annual discount for estimated timing of cash flows	(1,089,395)	(1,276,528)	(596,935)
Standardized measure of discounted future net cash flows	$ 858,147	$ 954,980	$ 598,498

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	For the Years Ended December 31,		
	2019	2018	2017
Beginning of period	$ 954,980	$ 598,498	$ 276,955
Sale of oil and gas produced, net of production costs	(233,677)	(204,566)	(125,992)
Net changes in prices and production costs	(372,233)	365,952	282,112
Extensions, discoveries and improved recoveries	45,728	153,691	103,937
Development costs incurred	185,086	127,788	24,121
Changes in estimated development cost	81,358	(52,260)	2,122
Purchases of minerals in place	10,135	—	—
Sales of minerals in place	(309)	(115,742)	—
Revisions of previous quantity estimates	79,637	12,341	14,119
Net change in income taxes	—	—	—
Accretion of discount	95,498	59,850	27,696
Changes in production rates and other	11,944	9,428	(6,572)
End of period	$ 858,147	$ 954,980	$ 598,498

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2019, 2018, and 2017 were calculated using the twelve-month arithmetic average of first-day-of-the-month price inclusive of adjustments for quality and location.

	For the Years Ended December 31,		
	2019	2018	2017
Oil (per Bbl)	$ 51.22	$ 59.29	$ 46.76
Gas (per Mcf)	$ 1.44	$ 2.28	$ 2.45
Natural gas liquids (per Bbl)	$ 10.07	$ 22.06	$ 19.57

NOTE 17 - QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2019 and 2018 (in thousands, except per share data):

2019	Three Months Ended March 31	Three Months Ended June 30	Three Months Ended September 30	Three Months Ended December 31
Oil and gas sales	$ 72,594	$ 85,783	$ 75,176	$ 79,667
Operating profit[(1)]	$ 40,818	$ 45,744	$ 34,148	$ 36,514
Net income (loss)	$ (6,993)	$ 41,022	$ 35,893	$ (2,855)
Basic net income (loss) per common share	$ (0.34)	$ 1.99	$ 1.74	$ (0.14)
Diluted net income (loss) per common share	$ (0.34)	$ 1.99	$ 1.74	$ (0.14)
2018	**March 31**	**June 30**	**September 30**	**December 31**
Oil and gas sales	$ 64,193	$ 71,872	$ 74,380	$ 66,213
Operating profit[(1)]	$ 35,042	$ 40,014	$ 43,959	$ 41,416
Net income	$ 13,870	$ 4,859	$ 43,363	$ 106,094
Basic net income per common share	$ 0.68	$ 0.24	$ 2.11	$ 5.16
Diluted net income per common share	$ 0.68	$ 0.24	$ 2.10	$ 5.15

(1) Oil and gas sales less lease operating expense, gas plant and midstream operating expense, gathering, transportation, and processing, severance and ad valorem taxes, depreciation, and depletion and amortization.

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

As disclosed in our Current Report on Form 8-K, filed on June 19, 2019, we engaged Deloitte & Touche LLP ("Deloitte") as the Company's new independent registered public accounting firm to audit the Company's financial statements for the fiscal year ending December 31, 2019, and dismissed Grant Thornton LLP ("Grant Thornton") as the Company's independent registered accounting firm. The decision to change the Company's independent registered accounting firm from Grant Thornton to Deloitte was approved by the Audit Committee of the Board.

During the fiscal years ended December 31, 2018 and December 31, 2017, and through June 19, 2019, there were no disagreements with Grant Thornton on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, that if not resolved to the satisfaction of Grant Thornton, would have caused Grant Thornton to make reference thereto in its reports on the Company's financial statements for such years.

During the fiscal years ended December 31, 2018 and 2017, and the subsequent interim period through June 19, 2019, there were no "reportable events" (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

As disclosed in our Current Report on Form 8-K, filed on April 19, 2017, we engaged Grant Thornton on April 13, 2017 as the Company's new independent registered public accounting firm to audit the Company's financial statements for the fiscal year ending December 31, 2017, and dismissed Hein & Associates LLP ("Hein") as the Company's independent registered accounting firm. The decision to change the Company's independent registered accounting firm from Hein to Grant Thornton was approved by the Audit Committee of the Board.

During the 2017 Predecessor Period, there were no disagreements with Hein on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, that if not resolved to the satisfaction of Hein, would have caused Hein to make reference thereto in its reports on the Company's financial statements for such years.

During the 2017 Predecessor Period, there were no "reportable events" (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

Item 9A. *Controls and Procedures*.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2019. The term "disclosure controls and procedures," as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company's management, including its principal executive and principal financial officers and internal audit function, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2019, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company's internal control system is supported by written policies and procedures, contains self-monitoring mechanisms, and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Management's Assessment of Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Principal Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2019, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2019, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2019, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended December 31, 2019 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Bonanza Creek Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Bonanza Creek Energy, Inc. and subsidiaries (the "Company") as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Company and our report dated February 27, 2020, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's 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 for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

February 27, 2020
Denver, Colorado

Item 9B. *Other Information*.

None.

PART III

Item 10. *Directors, Executive Officers, and Corporate Governance*.

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2019.

Our Board has adopted a Code of Business Conduct and Ethics applicable to all officers, directors, and employees, which is available on our website (www.bonanzacrk.com) under “Corporate Governance” under the “For Investors” tab. We will provide a copy of this document to any person, without charge, upon request by writing to us at Bonanza Creek Energy, Inc., Investor Relations, 410 17th Street, Suite 1400, Denver, Colorado 80202. We intend to satisfy the disclosure requirement under Item 406(c) of Regulation S-K regarding an amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on our website at the address and the location specified above.

Item 11. *Executive Compensation*.

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2019.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2019.

Item 13. *Certain Relationships and Related Transaction and Director Independence*.

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2019.

Item 14. *Principal Accounting Fees and Services*.

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2019.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

Exhibit Number	Description
2.1	Order Confirming Debtors' Third Amended Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code on April 7, 2017 (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 7, 2017)
2.2	Debtors' Third Amended Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 7, 2017)
3.1	Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017)
3.2	Fourth Amended and Restated Bylaws of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.2 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017)
4.1†	Description of Capital Stock
10.1	Restructuring Support Agreement, dated as of December 23, 2016 (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 23, 2016)
10.2	Backstop Commitment Agreement, dated as of December 23, 2016 (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 23, 2016)
10.3	Stipulation dated February 1, 2017 among the Debtors, the Ad Hoc Noteholder Group and Silo (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on February 3, 2017)
10.4	Restructuring Support and Lock-Up Agreement, dated as of February 16, 2017, among the Debtors and the RBL Lenders (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed on March 16, 2017)
10.5	Warrant Agreement dated as of April 28, 2017, among Bonanza Creek Energy, Inc. and Broadridge Investor Communication Solutions, Inc. as warrant agent (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.6*	Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.7*	Form of Non-Qualified Stock Option Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.8*	Form of Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.9*	Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018)
10.10*	Form of NYSE Inducement Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018)
10.11*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2019)
10.12*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on November 6, 2019)

10.13*	Form of Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018)
10.14*	Form of Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on May 8, 2019)
10.15*	Bonanza Creek Energy, Inc. Fifth Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Quarterly Report on Form 10-Q filed on May 8, 2018)
10.16*	Bonanza Creek Energy, Inc. Sixth Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2019)
10.17*	Form of Indemnification Agreement between Bonanza Creek Energy, Inc. and the directors and executive officers of Bonanza Creek Energy, Inc (incorporated by reference to Exhibit 10.7 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.18*	Employment Letter Agreement dated November 6, 2017 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on November 9, 2017)
10.19*	Letter Agreement dated June 20, 2019 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 20, 2019)
10.20*	Employment Letter Agreement dated March 30, 2018 between Bonanza Creek Energy, Inc. and Eric T. Greager (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018)
10.21*	Employment Letter Agreement dated November 12, 2018 between Bonanza Creek Energy, Inc. and Brant H. DeMuth (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 13, 2018)
10.22*†	Form of Officer Employment/Promotion Letter Agreement
10.23*	Credit Agreement, dated as of December 7, 2018, among Bonanza Creek Energy, Inc. as borrower, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and an issuing bank (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 10, 2018)
16.1	Letter from Grant Thornton LLP to the Securities and Exchange Commission, dated June 25, 2019 (incorporated by reference to Exhibit 16.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 25, 2019)
21.1†	List of subsidiaries
23.1†	Consent of Deloitte & Touche LLP
23.2†	Consent of Grant Thornton LLP
23.3†	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.
31.1†	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2†	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1†	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
32.2†	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
99.1†	Report of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. for reserves as of December 31, 2019
101†	The following material from the Bonanza Creek Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2019 (and related periods), formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations and Comprehensive Income, (iii) the Condensed Consolidated Statements of Stockholders' Equity, (iv) the Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text
104	Cover Page Interactive Data File (formatted as Inline XBRL)

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* Management Contract or Compensatory Plan or Arrangement
† Filed or furnished herewith

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.

		BONANZA CREEK ENERGY, INC.	
Date:	February 27, 2020	By:	/s/ Eric T. Greager
			Eric T. Greager, *President and Chief Executive Officer* *(principal executive officer)*

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Eric T. Greager, Brant DeMuth, Cyrus D. Marter IV, and Sandi K. Garbiso 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 annual report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	February 27, 2020	By:	/s/ Eric T. Greager
			Eric T. Greager, President and Chief Executive Officer *(principal executive officer)*
Date:	February 27, 2020	By:	/s/ Brant DeMuth
			Brant DeMuth, Executive Vice President and Chief Financial Officer *(principal financial officer)*
Date:	February 27, 2020	By:	/s/ Sandi K. Garbiso
			Sandi K. Garbiso, *Vice President and Chief Accounting Officer* *(principal accounting officer)*
Date:	February 27, 2020	By:	/s/ Brian Steck
			Brian Steck, *Chairman of the Board*
Date:	February 27, 2020	By:	/s/ Carrie Hudak
			Carrie Hudak, *Director*
Date:	February 27, 2020	By:	/s/ Paul Keglevic
			Paul Keglevic, *Director*
Date:	February 27, 2020	By:	/s/ Thomas B. Tyree, Jr.
			Thomas B. Tyree, Jr., *Director*
Date:	February 27, 2020	By:	/s/ Jack E. Vaughn
			Jack E. Vaughn, *Director*
Date:	February 27, 2020	By:	/s/ Scott D. Vogel
			Scott D. Vogel, *Director*
Date:	February 27, 2020	By:	/s/ Jeffrey E. Wojahn
			Jeffrey E. Wojahn, *Director*

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

Throughout this exhibit, the terms "BCEI," "we," "us," "our" and the "Company" refer to Bonanza Creek Energy, Inc. The following summary of terms of our common stock, par value $0.01 per share (the "Common Stock"), is based upon our third amended and restated certificate of incorporation (the "Certificate of Incorporation") and fourth amended and restated bylaws (the "Bylaws") currently in effect under Delaware law. This summary is not complete and is subject to, and qualified in its entirety by reference to, the Certificate of Incorporation and the Bylaws. For a complete description of the terms and provisions of the Common Stock, refer to the Certificate of Incorporation and Bylaws, which are filed as exhibits to our Registration Statement on Form 8-A12B. We encourage you to read these documents and the applicable portions of the Delaware General Corporation Law, as amended (the "DGCL"), carefully.

Authorized Capital

Our authorized capital stock consists of 250,000,000 shares, which include 225,000,000 shares of Common Stock (the "Common Stock") and 25,000,000 shares of preferred stock, par value $0.01 per share (the "Preferred Stock"). No shares of Preferred Stock have been issued.

Common Stock

Voting Rights. Holders of the Common Stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of the Common Stock do not have cumulative voting rights in the election of directors. The affirmative vote of at least a majority of our outstanding voting stock will be required to amend or repeal provisions of our Certificate of Incorporation.

Dividend and Liquidation Rights. Holders of the Common Stock may receive dividends when, as and if declared by our board of directors out of funds lawfully available for the payment of dividends. As a Delaware corporation, we may pay dividends out of surplus or, if there is no surplus, out of net profits for the fiscal year in which a dividend is declared and/or the preceding fiscal year. Section 170 of the DGCL also provides that dividends may not be paid out of net profits if, after the payment of the dividend, capital is less than the capital represented by the outstanding stock of all classes having a preference upon the distribution of assets.

The right of holders of the Common Stock to receive dividends and distributions upon liquidation will be subject to the satisfaction of any applicable preference granted to the holders of any Preferred Stock that may then be outstanding.

No Preemptive, Conversion or Redemption Rights. The Common Stock has no preemptive, conversion or exchange rights and is not subject to further calls or assessment by us. There are no redemption, retraction, purchase for cancellation or sinking fund provisions applicable to the Common Stock, nor are there any provisions discriminating against any existing or prospective holder of the Common Stock as a result of such holder owning a substantial amount of Common Stock.

Certain Anti-Takeover Matters

Certificate of Incorporation and Bylaws. Our Certificate of Incorporation and Bylaws contain provisions that we describe in the following paragraphs, which may delay, defer, or prevent a change in control of our company, the removal of our existing management or directors, or an offer by a potential acquirer to our stockholders, including an offer by a potential acquirer at a price higher than the market price for the stockholders' shares.

Among other things, our Certificate of Incorporation and Bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 120 days and not more than 150 days prior to the first anniversary date of the annual meeting for the preceding year. Our Bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated Preferred Stock. This ability makes it possible for our board of directors to issue, without stockholder approval, Preferred Stock with voting or other rights or preferences that could impede the success of any attempt to change control of us;
- provide that the authorized number of directors may be changed only by resolution of the board of directors;
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;
- provide that stockholders may only act at a duly called meeting and may not act by written consent in lieu of a meeting;
- provide that stockholders are not permitted to call special meetings of stockholders. Only our board of directors, Chairperson, Chief Executive Officer and President are permitted to call a meeting of stockholders; and
- provide that our board of directors may alter or repeal our Bylaws or approve new bylaws without further stockholder approval.

Delaware Anti-Takeover Law. Our company is a Delaware corporation subject to the provisions of Section 203 of the DGCL, an anti-takeover law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a "business combination" as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an "interested stockholder" as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation's voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholder becoming an interested stockholder prior to the date the person attained the status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors or officers and issued pursuant to employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or
- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of the Common Stock. With approval of our stockholders, we could amend our Certificate of Incorporation in the future to elect not to be governed by the anti-takeover law.

Exhibit 10.22

[date]

[Recipient]
[address]
[address]

Re: Employment Terms and Conditions – [job position]

Dear [recipient]:

[[Thank you for your continued service to Bonanza Creek Energy, Inc. (the "**Company**"). The Company] [Bonanza Creek Energy, Inc. (the "**Company**")]] is excited to offer you [[a promotion to the position of] [an employment position as]] [job position] reporting to [supervisor] as [supervisor's title] effective as of [effective date]. In summary, as [job position] your compensation will be:

- An annual salary of $______ ("**Base Salary**"), to be paid on a bi-weekly basis, subject to all withholdings and deductions;
- Continued participation in the Company's 2017 Long Term Incentive Program ("**LTIP**"), subject to the terms and conditions of the LTIP and the award agreement(s) to be entered into thereunder, at the discretion of the Company's Compensation Committee and Board of Directors;
- Continued participation in the Company's Short Term Incentive Program (the "**STIP**") as further discussed below;
- Participation in the Company's No Tracking Vacation Program; ten (10) days sick leave annually; and eleven (11) paid holidays per year, all in accordance with the Company's benefits policy;
- Option to participate or continue to participate in the Company's 401(k) Plan, in accordance with such plan; currently the Company provides matching contributions of 6% of W-2 income, which amount may be amended from time to time in accordance with the terms of the 401(k) Plan;
- Option to participate or continue to participate in the Company's health insurance plans upon your election subject to the terms and conditions of the plans;
- Option to participate or to continue to participate in the Company's flexible benefit plan (Section 125 Plan); and
- Participation in the Company's Executive Change in Control and Severance Plan (the "**Severance Plan**") as a Tier __ Executive (as such term is defined in the Severance Plan), a copy of which is attached hereto as **Exhibit A**.

As you know, the STIP is administered by the Compensation Committee and Board of Directors of the Company. The STIP has been designed to supplement your base salary and provide a year-over-year short term incentive cash bonus payment opportunity when the Company meets or exceeds its goals. Your "target" cash bonus opportunity as [job position] for 20__ will be equal to __% of Base Salary, based on Company performance achievement as well as your individual performance achievement.[1] Bonuses under the STIP for each year, if any, will typically be paid in March of the following year.

[1] Add the following language at the end of this sentence if applicable for prorated STIP: ", and will be calculated on a pro-rata basis for 20__ based on the number of days in 20__ during which you were [job position] and the number of days in 20__ during which you were [prior job position] at the __% target level.

The Company may modify compensation and benefits from time to time as it deems necessary in accordance with the terms and conditions of the plans set forth above and the Company's policies.

The terms and conditions of employment set forth in this Employment Letter are contingent upon your execution of the Company's Employee Restrictive Covenants, Proprietary Information and Inventions Agreement attached hereto ("**PIIA**") attached hereto as **Exhibit B**. You will continue to be expected to abide by the Company's rules and regulations, as such may be modified by the Company from time to time.

Notwithstanding anything to the contrary, your employment with the Company is AT WILL. You may terminate your employment with the Company at any time and for any reason whatsoever simply by notifying the Company, subject only to any rights or obligations that may be required by the Severance Plan or PIIA, each as may be amended from time to time. Likewise, the Company may terminate your employment at any time and for any reason whatsoever, with or without cause or advance notice, subject only to any rights and obligations that may be required by the Severance Plan or PIIA, as each may be amended from time to time.

In consideration for the benefits to be provided to you under this Employment Letter to which you are not currently entitled, by executing this Employment Letter, you hereby (i) accept the terms of employment outlined in this Employment Letter and (ii) acknowledge and agree that this Employment Letter constitutes the entire agreement between you and the Company concerning your employment (except as otherwise may be set forth in the LTIP and any agreements entered into thereunder, the STIP, the Severance Plan, the PIIA or the Indemnity Agreement to be entered into between you and the Company attached hereto as **Exhibit C** (collectively, the "**Additional Agreements**")), and supersedes and terminates all prior and contemporaneous agreements and understandings, both written and oral, between the parties with respect to its subject matters, except for the Additional Agreements. You agree that the Company has not made any promise or representation to you concerning this Employment Letter not expressed in this Employment Letter, and that, in signing this Employment Letter, you are not relying on any prior oral or written statement or representation by the Company, but are instead relying solely on your own judgment and the judgment of your legal and tax advisors, if any.

Again, we are thrilled to offer you this promotion and look forward to working with you in this new role. If you have any questions or need additional information, please let me know.

Sincerely,

Name:
Title:

Accepted and agreed:

[recipient]
Date: ______________________________

Exhibit A
Executive Change in Control and Severance Plan

Exhibit B
Employee Restrictive Covenants, Proprietary Information and Inventions Agreement

BONANZA CREEK ENERGY, INC.
EMPLOYEE RESTRICTIVE COVENANTS, PROPRIETARY INFORMATION AND INVENTIONS AGREEMENT

In consideration of my employment or continued employment by Bonanza Creek Energy, Inc., a Delaware corporation (collectively with its subsidiaries and affiliates, the "**Company**"), and the compensation now and hereafter paid to me, I hereby agree as follows:

1. **Nondisclosure.**

1.1. **Recognition of Company's Rights; Nondisclosure.** At all times during my employment and thereafter, I will hold in strictest confidence and will not disclose, use, lecture upon or publish any of the Company's Proprietary Information (as defined below), except as such disclosure, use or publication may be required in connection with my work for the Company, or unless an officer of the Company expressly authorizes such in writing. I will obtain the Company's written approval before publishing or submitting for publication any material (written, verbal, or otherwise) that incorporates any Proprietary Information. I hereby assign to the Company any rights I may have or acquire in such Proprietary Information and recognize that all Proprietary Information will be the sole property of the Company and its assigns.

1.2. **Proprietary Information.** The term "**Proprietary Information**" means any and all confidential and/or proprietary knowledge, data or information of the Company. By way of illustration, but not limitation, "**Proprietary Information**" includes all technical and non-technical information of the Company including (a) trade secrets, including, but not limited to, the whole or any portion or phase of any scientific or technical information, design, process, procedure, improvement, confidential business or financial information, listing or name, addresses or telephone number, or other information relating to any business that is secret and of value; (b) inventions, ideas, materials, concepts, processes, formulas, data, other works of authorship, know-how, improvements, discoveries, developments, designs, techniques, drilling reports, maps, well logs, mud logs, seismic data and geological or geophysical data and analyses (collectively, "**Inventions**"); (c) information regarding research, development, production, marketing and selling, business plans, budgets and unpublished financial statements, licenses, prices and costs, suppliers and customers and the existence of any business discussions, negotiations or agreements between the Company and any third party; and (d) information regarding the skills and compensation of the Company's employees, contractors or other service providers.

1.3. **Third Party Information.** I understand, in addition, that the Company has received and in the future will receive from third parties confidential or proprietary information ("**Third Party Information**") subject to a duty on the Company's part to maintain the confidentiality of such information and to use it only for certain limited purposes. During the term of my employment and thereafter, I will hold Third Party Information in the strictest confidence and will not disclose to anyone (other than Company personnel who need to know such information in connection with their work for the Company) or use, except in connection with my work for the Company, Third Party Information unless expressly authorized by an officer of the Company in writing.

1.4. **No Improper Use of Information of Prior Employers and Others.** During my employment by the Company, I will not improperly use or disclose any confidential information or trade secrets, if any, of any former employer or any other person to whom I have an obligation of confidentiality, and I will not bring onto the premises of the Company any unpublished documents or any property belonging to any former employer or any other person to whom I have an obligation of confidentiality unless consented to in writing by that former employer or person. I will use in the performance of my duties only information which is generally known and used by persons with training and experience comparable to my own, which is common knowledge in the industry or otherwise legally in the public domain, or which is otherwise provided or developed by the Company.

2. **Promise of Access to Proprietary Information, Specialized Training, and Goodwill**

2.1. **Access to Proprietary Information**. During my employment, the Company agrees to provide me with access to Proprietary Information relevant to my position and responsibilities. The Company promises to disclose Proprietary Information to me in order to enable me to perform the duties and responsibilities of my position for the Company. I further acknowledge that, prior to my employment at the Company, I was unfamiliar with Proprietary Information. Finally, I acknowledge that the unauthorized disclosure of Proprietary Information could place the Company at a competitive disadvantage.

2.2. **Access to Specialized Training.** To the extent appropriate to my position, the Company also promises that it will provide me with specialized training and instruction regarding (a) the methods, products and services designed, developed, enhanced, modified, manufactured, sold or provided by or for the Company, (b) the Company's operations, (c) marketing and operational techniques and strategies, and (d) the Company's technology. The Company promises to provide specialized training and instruction to me regardless of whether I become or remain employed by the Company, in order to enable me to perform duties for the Company. I agree to use this training for the Company's exclusive benefit, and agrees not to use such training in a way that would harm the Company's business interests during employment and thereafter.

2.3. **Access to Goodwill.** I acknowledge that the Company has developed, over a period of time, and will continue to develop, significant relationships and goodwill between itself and its customers and suppliers by providing superior products and services. I further acknowledge that these relationships and this goodwill are a valuable asset belonging solely to the Company. I further acknowledge that any business relationship that Employee brings or has brought to the Company will belong to and will inure to the benefit of the Company after I begin employment. Finally, I acknowledge that the responsibility to build and maintain business relationships and goodwill with current and prospective customers creates a special relationship of trust and confidence between me, the Company, and such customers. The Company promises to permit me to use its goodwill in contacting and in doing business with its current and prospective customers and suppliers. The Company further promises to compensate me according to its normal payroll procedures while I build and/or maintain the Company's business relationships and goodwill with its current and prospective customers and suppliers. If and when appropriate, and pursuant to company policy and procedure, the Company agrees to reimburse me for reasonable and necessary business expenses incurred in building and maintaining business relationships and goodwill with the Company's current and prospective customers and suppliers.

3. **Assignment of Inventions.**

3.1. **Proprietary Rights.** The term "**Proprietary Rights**" means all trade secret, patent, copyright, moral rights and other intellectual property rights throughout the world.

3.2. **Previous Inventions.** Inventions, if any, patented or unpatented, which I made prior to the commencement of my employment with the Company are excluded from the scope of this Agreement. To preclude any possible uncertainty, within two (2) business days following my signing of this Agreement, I will provide to the Company a complete written list of all Inventions relevant to the subject matter of my employment by the Company that I have, alone or jointly with others, conceived, developed or reduced to practice or caused to be conceived, developed or reduced to practice prior to the commencement of my employment with the Company, that I consider to be my property or the property of third parties and that I wish to have excluded from the scope of this Agreement (collectively referred to as "**Previous Inventions**"). If I do not timely provide the Company with my written list of Previous Inventions, I represent that there are no Previous Inventions. If, in the course of my employment with the Company, I incorporate a Previous Invention into any work product for the Company, the Company is hereby granted and will have a nonexclusive, royalty-free, irrevocable, perpetual, worldwide license (with rights to sublicense through multiple tiers of sublicensees) to make, have made, modify, use, reproduce, make derivative works of, distribute, publicly perform, publicly display, import and sell such Previous Invention. Notwithstanding the foregoing, I agree that I will not incorporate, or permit to be incorporated, Previous Inventions in any Company Inventions without the Company's prior written consent.

3.3. **Assignment of Inventions.** Subject to Sections 3.4 and 3.6, I hereby assign and agree to assign in the future (when any such Inventions or Proprietary Rights are first reduced to practice or first fixed in a tangible medium, as applicable) to the Company all my right, title and interest in and to any and all Inventions (and all Proprietary Rights with respect thereto) whether or not patentable or registrable under copyright or similar statutes, made or conceived or reduced to practice or learned by me, either alone or jointly with others, during the period of my employment with the Company. Inventions assigned to the Company, or to a third party as directed by the Company pursuant to this Section 3, are hereinafter referred to as "**Company Inventions**." I hereby forever waive and agree not to assert any and all Proprietary Rights I may have in or with respect to a Company Invention.

3.4. **Nonassignable Inventions.** I recognize that, in the event of a specifically applicable state law, regulation, rule, or public policy ("**Specific Inventions Law**"), this Agreement will not be deemed to require assignment of any invention which qualifies fully for protection under a Specific Inventions Law by virtue of the fact that any such invention was, for example, developed entirely on my own time without using the Company's equipment, supplies, facilities, or trade secrets and neither related to the Company's actual or anticipated business, research or development, nor resulted or was derived from work performed by me directly or indirectly for the Company. In the absence of a Specific Inventions Law, the preceding sentence will not apply.

3.5. **Obligation to Keep Company Informed.** During the period of my employment and for one (1) year after termination of my employment with the Company, I will promptly disclose to the Company fully and in writing all Inventions authored, conceived or reduced to practice by me, either alone or jointly with others. In addition, I will promptly disclose to the Company all patent applications filed by me or on my behalf or in which I am named as an inventor or co-inventor within one (1) year after termination of employment. At the time of each such disclosure, I will advise the Company in writing of any Inventions that I believe fully qualify for protection under the provisions of a Specific Inventions Law; and I will at that time provide to the Company in writing all evidence necessary to substantiate that belief. The Company will keep in confidence and will not use for any purpose or disclose to third parties without my consent any confidential information disclosed in writing to the Company pursuant to this Agreement relating to Inventions that qualify fully for protection under a Specific Inventions Law. I will preserve the confidentiality of any Invention that does not fully qualify for protection under a Specific Inventions Law.

3.6. **Government or Third Party.** I also agree to assign all my right, title and interest in and to any particular Company Invention to a third party, including, without limitation, the United States, as directed by the Company.

3.7. **Works for Hire.** I acknowledge that all original works of authorship which are made by me (solely or jointly with others) within the scope of my employment and which are protectable by copyright are "works made for hire," pursuant to United States Copyright Act (17 U.S.C., Section 101).

3.8. **Enforcement of Proprietary Rights.** I will assist the Company in every proper way to obtain, and from time to time enforce, United States and foreign Proprietary Rights relating to Company Inventions in any and all countries. To that end I will execute, verify and deliver such documents and perform such other acts (including appearances as a witness) as the Company may reasonably request for use in applying for, obtaining, perfecting, evidencing, sustaining and enforcing such Proprietary Rights and the assignment thereof. In addition, I will execute, verify and deliver assignments of such Proprietary Rights to the Company or its designee. My obligation to assist the Company with respect to Proprietary Rights relating to such Company Inventions in any and all countries will continue beyond the termination of my employment, but the Company will compensate me at a reasonable rate after my termination for the time actually spent by me at the Company's request on such assistance.

3.9. **Further Assurances.** In the event the Company is unable for any reason, after reasonable effort, to secure my signature on any document needed in connection with the actions specified in the preceding paragraph, I hereby irrevocably designate and appoint the Company and its duly authorized officers and agents as my agent and attorney in fact, which appointment is coupled with an interest, to act for and in my behalf to execute, verify and file any such documents and to do all other lawfully permitted acts to further the purposes of this Section 2 with the same legal force and effect as if executed by me. I hereby waive, assign and quitclaim to the Company any and all claims, of any nature whatsoever, which I now or may hereafter have for infringement of any Proprietary Rights assigned hereunder to the Company.

3.10. **Presumption of Ownership.** Due to the difficulty of establishing when an Invention is first conceived or developed, whether it results from access to the Company's actual or anticipated business or research or development, or whether it is a direct or indirect result or derivation of any work I perform for the Company, I hereby acknowledge and agree that ownership of all Inventions conceived, developed, suggested or reduced to practice by me, alone or jointly with others during my employment shall be presumed to belong to the Company and I shall have the burden of proof to prove otherwise.

4. **Records.** Unless otherwise directed or requested by the Company, I agree to keep and maintain adequate and current records (in the form of notes, sketches, drawings and in any other form that may be required by the Company) of all Proprietary Information developed by me and all Company Inventions made by me during the period of my employment at the Company, which records will be available to and remain the sole property of the Company at all times.

5. **No Conflicts.** I acknowledge that during my employment I will have access to and knowledge of Proprietary Information. To protect the Company's Proprietary Information, I agree that during the period of my employment by the Company I will not, without the Company's express written consent, engage in any other employment or business activity which is competitive with the Company, or would otherwise conflict with my obligations to the Company, except that nothing herein shall prevent my service on corporate, civic, charitable or industry boards or committees.

6. **Non-Compete and Non-Solicitation Obligations.**

6.1. Definitions.

a. "**Business**" shall mean the acquisition, exploration, development and production of onshore oil, natural gas and associated liquids in the United States of America.

b. "**Business Opportunities**" shall mean all business ideas, prospects, proposals or other opportunities pertaining to the Business, that are or were developed by me during my employment with the Company or any of the Company's Affiliates or originated by any third party and brought to my attention during my employment with the Company or any of the Company's Affiliates and in such capacity, together with information relating thereto (including, without limitation, geological and seismic data and interpretations thereof, whether in the form of maps, charts, logs, seismographs, calculations, summaries, memoranda, opinions or other written or charted means).

c. "**Post-Termination Non-Compete Term**" shall mean the same time period of time as the Severance Obligation Period (as that term is defined in the Executive Change in Control and Severance Plan, as amended).

6.2. **Covenant Not to Compete During Term of Employment.** I acknowledge that, during my employment with the Company, I will have access to and knowledge of Proprietary Information, including, without limitation, trade secret information. During the term of my employment with the Company and except as provided below or as otherwise permitted by the Company (acting upon the instruction of the board of directors of the Company), to protect the Company's Proprietary Information, I agree that:

a. I shall not, other than through the Company or any person that directly or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with, the Company and any predecessor to any such entity (each a "**Company Affiliate**" and collectively, the "**Company's Affiliates**"), engage or participate in any manner, whether directly or indirectly for my direct benefit through a family member or as an employee, employer, consultant, agent, principal, partner, more than five percent shareholder, officer, director, licensor, lender, lessor, or in any other individual or representative capacity, in (i) any business or activity that is competitive with the Business (as defined above), (ii) any business or activity that is engaged in leasing, acquiring, exploring, developing or producing hydrocarbons and related products, or (iii) any enterprise in which a material portion of its business is materially competitive in any way with any business in which the Company or any of the Company’s Affiliates is engaged during my employment with the Company or any of the Company’s Affiliates (including, without limitation, any business if the Company devoted material resources to entering into such business); and

b. all investments made by me (whether in my own name or for my direct benefit through an immediate family member or intermediary)(collectively, “**Employee Affiliates**), which relate to the Business or the lease, acquisition, exploration, development or production of hydrocarbons and related products shall be made solely through the Company or any of the Company’s Affiliates; and I shall not (directly or indirectly), and shall not permit any Employee Affiliates to: (i) invest or otherwise participate alongside the Company or any of the Company’s Affiliates in any Business Opportunities (as defined above) or (ii) invest or otherwise participate in any business or activity relating to a Business Opportunity, regardless of whether the Company or any of the Company’s Affiliates ultimately participates in such business or activity; provided, however, that this Section 6.2 shall not apply to (w) the existing personal oil and gas investments owned by me, my family members or any Employee Affiliates as of the date of this Agreement set forth on **Exhibit A** hereto (the “**Existing Personal Investments**”), (x) future expenditures made by me, my family members or any Employee Affiliates in the Existing Personal Investments, provided that such future expenditures do not go beyond the limited allowed for Permitted Investments (as defined below), (y) Permitted Investments (as defined below) and (z) any opportunity that is first offered to, and subsequently declined by, the Company (acting through the Company’s board of directors of the Company or its designee), if and to the extent that such opportunities are outside the Geographic Scope (as defined below). For purposes of this Agreement, “**Permitted Investments**” means passive investments in securities or other ownership interests of businesses made by me, my family members or any Employee Affiliates, provided that the aggregate amount owned by me, my family members and Employee Affiliates does not exceed 5% of the outstanding securities or other ownership interests of any such business.

6.3. **Covenant Not to Compete After the Date of Termination**. I hereby acknowledge and agree that the purpose of this Section 6.3 is to protect the Company from unfair loss of goodwill and business advantage, to shield me from the pressure to use or disclose Proprietary Information or to trade on the goodwill belonging to the Company, for the protection of the Company’s trade secret and Proprietary Information, and because of the knowledge I have acquired or will acquire as an executive or management personnel, or as an officer, or as profession staff to executive and management personnel. Accordingly, during the Post-Termination Non-Compete Term, I agree not to engage or participate in any manner, whether directly or indirectly for my benefit, through a family member, or as an employee, employer, consultant, agent, principal, partner, shareholder, officer, director, licensor, lender (other than as an employee of a chartered commercial bank with assets of $500 million or greater), lessor, or in any other individual or representative capacity, in any business engaged in leasing, acquiring, exploring, developing, or producing hydrocarbons and related products within the boundaries of, or within a twenty-five (25) mile radius of the boundaries of, any mineral property interest of the Company or the Company’s Affiliates (including, without limitation, a mineral lease, overriding royalty interest, production payment, net profits interest, mineral fee interest, or option or right to acquire any of the foregoing, or an area of mutual interest as designated pursuant to contractual agreement between the Company or any of the Company’s Affiliates and any third party) or any other property on which the Company or the Company’s Affiliates have a right, license, or authority to conduct or direct exploratory activities, such as three dimensional seismic acquisitions or other seismic, geophysical, and geochemical activities as of the date my employment with the Company is terminated (the “**Geographic Scope**”); provided, however, that this subparagraph shall not be construed to preclude me from (w) holding the Existing Personal Investments, (x) making future expenditures made by me, my family members or any Employee Affiliates in the Existing Personal Investments, provided that such future expenditures do not go beyond the limited allowed for Permitted Investments, (y) making Permitted Investments and (z) investing in any opportunity that is first offered to, and subsequently declined by, the Company (acting through the board of directors of the Company or its designee), if and to the extent that such opportunities are outside the Geographic Scope.

6.4. **Covenant Not to Solicit.** I shall not, during my employment with the Company or the Post-Termination Non-Compete Term (a) directly or indirectly, on behalf of myself or any third party, solicit, encourage, facilitate, or induce any advertiser, supplier, broker, vendor, agent, sales representative, employee, contractor, consultant, or licensee of the Company or of the Company's Affiliates to breach any agreement or contract with, or discontinue or curtail his, her or its business relationships with the Company or any of the Company's Affiliates or (b) directly or indirectly, solicit, recruit, induce, or otherwise engage as an employee, independent contractor or otherwise, either for myself or any other third party, any person who is employed by the Company or any of the Company's Affiliates at the time of such solicitation, recruitment or inducement.

6.5. **Non-Disparagement**. I shall not, during my employment with the Company or the Post-Termination Non-Compete Term, make to any other person or party any statement (whether oral, written, electronic, anonymous, on the internet, or otherwise), which directly or indirectly impugns the quality or integrity of the Company or its Affiliates' business or employment practices, operations, or services, or any other disparaging or derogatory remarks about the Company or its Affiliates.

7. **No Conflicting Obligation.** I represent that my performance of all the terms of this Agreement and as an employee of the Company does not and will not breach any non-compete agreement or any agreement to keep in confidence information acquired by me in confidence or in trust prior to my employment by the Company. I have not entered into, and I agree I will not enter into, any agreement either written or oral in conflict with this Agreement.

8. **Return Of Company Documents.** When I leave the employ of the Company or upon request by the Company during the course of my employment, I will deliver to the Company any and all property, equipment, drawings, notes, memoranda, specifications, devices, formulas, and documents, together with all copies thereof, and any other material containing or disclosing any Company Inventions, Third Party Information or Proprietary Information of Company. I agree that I will not copy, delete or alter any information contained on my Company computer before I return it to Company. I further agree that any property situated on Company's premises and owned by the Company, including disks and other storage media, filing cabinets or other work areas, is subject to inspection by Company personnel at any time with or without notice. I understand and agree that compliance with this paragraph may require that data be removed from my personal computer equipment or other electronic storage devices or media. Consequently, upon reasonable prior notice, I agree to permit the qualified personnel of Company and/or its contractors access to such computer equipment or other electronic storage devices or media for that purpose. Prior to leaving, I will cooperate with the Company in completing and signing the Company's termination statement.

9. **Legal And Equitable Remedies.** Because my services are personal and unique and because I may have access to and become acquainted with the Company's Proprietary Information, the Company has the right to enforce this Agreement and any of its provisions by injunction, specific performance or other equitable relief, without bond and without prejudice to any other rights and remedies that the Company may have for a breach of this Agreement. This paragraph shall not be construed as an election of any remedy, or as a waiver of any right available to Company under this Agreement or the law, including the right to seek damages from me for a breach of any provision of this Agreement, nor shall this paragraph be construed to limit the rights or remedies available under applicable law or in equity for any violation of any provision of this Agreement, including, but not limited to claims for damages. If employee violates and covenant contained in Section 5, the duration of such covenant shall be automatically extended for the period of time equal to the period of such violation.

10. **Notices.** Any notices required or permitted hereunder will be given to the appropriate party at the address specified below or at such other address as the party may specify in writing. Such notice will be deemed given upon personal delivery to the appropriate address or if sent by certified or registered mail, three (3) days after the date of mailing.

11. **Notification Of New Employer.** In the event that I leave the employ of the Company, I hereby consent to the notification of my new employer of my rights and obligations under this Agreement.

12. **General Provisions.**

12.1. **Governing Law; Consent to Personal Jurisdiction.** This Agreement will be governed by and construed according to the laws of the State of Colorado, without regard for its conflicts of law principles that would require application of the laws of a different state. I hereby expressly consent to the personal jurisdiction of the state and federal courts located in Denver, Colorado for any lawsuit filed there against me by Company arising from or related to this Agreement.

12.2. **Attorneys' Fees and Costs.** Should the Parties take any action or commence any legal proceeding relating to this Agreement, if either Party prevails in all or any part of its claims or defenses, such Party shall be entitled to recover all costs and expenses from the other party, including reasonable attorneys' fees, incurred in connection with such action or other legal proceeding.

12.3. **Severability.** In case any one or more of the provisions contained in this Agreement is, for any reason, held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability will not affect the other provisions of this Agreement, and this Agreement will be construed as if such invalid, illegal or unenforceable provision had never been contained herein. Notwithstanding the foregoing, if any one or more of the provisions contained in this Agreement is held to be excessively broad as to duration, geographical scope, activity or subject, for any reason, it will be construed by limiting and reducing it, so as to be enforceable to the extent compatible with the applicable law as it then appears.

12.4. **Successors and Assigns.** This Agreement will be binding upon my heirs, executors, administrators and other legal representatives and will be for the benefit of the Company, its successors, and its assigns. This Agreement and shall be freely assignable by Company in its sole discretion, at any time, without the requirement of notice or consent by me.

12.5. **Survival.** The provisions of this Agreement will survive the termination of my employment and the assignment of this Agreement by the Company to any successor in interest or other assignee.

12.6. **Employment.** I acknowledge and agree that my relationship with the Company is "AT-WILL", and that both the Company and I may terminate my employment relationship at any time, with or without cause or advance notice. I further agree and understand that nothing in this Agreement will confer any right with respect to continuation of employment by the Company, nor will it interfere in any way with my right or the Company's right to terminate my employment at any time, with or without cause or advance notice.

12.7. **Waiver.** No waiver by the Company of any breach of this Agreement will be a waiver of any preceding or succeeding breach. No waiver by the Company of any right under this Agreement will be construed as a waiver of any other right. The Company will not be required to give notice to enforce strict adherence to all terms of this Agreement.

12.8. **Entire Agreement.** The obligations pursuant to Sections 1 and 2 of this Agreement will apply to any time during which I was previously employed, or am in the future employed, by the Company as a consultant if no other agreement governs nondisclosure and assignment of inventions during such period. This Agreement is the final, complete and exclusive agreement of the parties with respect to the subject matter hereof and supersedes and merges all prior discussions and agreements between us relating to the subject matter hereof. No modification of or amendment to this Agreement, nor any waiver of any rights under this Agreement, will be effective unless in writing and signed by the party to be charged. Any subsequent change or changes in my duties, salary or compensation will not affect the validity or scope of this Agreement.

12.9. **Advice of Counsel.** I ACKNOWLEDGE THAT, IN EXECUTING THIS AGREEMENT, I HAVE HAD THE OPPORTUNITY TO SEEK THE ADVICE OF INDEPENDENT LEGAL COUNSEL, AND I HAVE READ AND UNDERSTOOD ALL OF THE TERMS AND PROVISIONS OF THIS AGREEMENT. THIS AGREEMENT MAY NOT BE CONSTRUED AGAINST ANY PARTY BY REASON OF THE DRAFTING OR PREPARATION HEREOF.

[**Signatures on Following Page]**

This Agreement is effective as of [date]

I HAVE READ THIS AGREEMENT CAREFULLY AND UNDERSTAND ITS TERMS.

Dated: ____

Signature
Name: [recipient]

Bonanza Creek Energy, Inc.

By: ________________________________
Name:
Title:
Dated: ______________________________

Exhibit A
Existing Investments

Exhibit C
Indemnity Agreement

Exhibit 21.1

Subsidiaries of Bonanza Creek Energy, Inc., a Delaware corporation

Bonanza Creek Energy Operating Company, LLC, a Delaware limited liability company

Holmes Eastern Company, LLC, a Delaware limited liability company

Rocky Mountain Infrastructure, LLC, a Delaware limited liability company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-229431 and 333-217545 on Form S-8 of our reports dated February 27, 2020, relating to the financial statements of Bonanza Creek Energy, Inc. and its subsidiaries and the effectiveness of Bonanza Creek Energy, Inc. and its subsidiaries' internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP
Denver, Colorado
February 27, 2020

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 27, 2019 with respect to the consolidated financial statements included in the Annual Report of Bonanza Creek Energy, Inc. on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said report in the Registration Statements of Bonanza Creek Energy, Inc. on Forms S-8 (File No. 333-229431 and File No. 333-217545).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2020

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Bonanza Creek Energy, Inc. for the year ended December 31, 2019. We further consent to the incorporation by reference thereof into Bonanza Creek Energy, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-217545 and 333-229431).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 27, 2020

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a- 14(a)

I, Eric T. Greager, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2019 of Bonanza Creek 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 periods 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 fiscal 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.

Date: February 27, 2020

/s/ Eric T. Greager

Eric T. Greager
President and Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATION OF THE PRINCIPAL FINANCIAL OFFICER PURSUANT TO RULE 13a- 14(a)

I, Brant DeMuth, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2019 of Bonanza Creek 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 periods 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 fiscal 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.

Date: February 27, 2020

/s/ Brant DeMuth

Brant DeMuth

Executive Vice President and Chief Financial Officer *(principal financial officer)*

Exhibit 32.1

Certification of the Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Bonanza Creek Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Eric T. Greager, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2020

/s/ Eric T. Greager

Eric T. Greager

President and Chief Executive Officer
(principal executive officer)

Exhibit 32.2

Certification of the Principle Financial Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Bonanza Creek Energy, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Brant DeMuth, Executive Vice President and Chief Financial Officer, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2020

/s/ Brant DeMuth

Brant DeMuth

Executive Vice President and Chief Financial Officer *(principal financial officer)*

January 30, 2020

Mr. Jeffrey E. Wojahn
Reserves Committee of Bonanza Creek Energy, Inc.
c/o Bonanza Creek Energy, Inc.
410 Seventeenth Street, Suite 1400
Denver, Colorado 80202

Dear Mr. Wojahn:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the interest of Bonanza Creek Energy, Inc. and its wholly-owned direct and indirect subsidiaries (collectively, BCEI) in certain oil and gas properties located in Wattenberg Field, Colorado. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by BCEI. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for BCEI's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the BCEI interest in these properties, as of December 31, 2019, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	25,397.0	11,566.1	105,840.3	998,484.4	569,877.0
Proved Undeveloped	39,016.5	10,594.9	106,360.3	949,057.5	288,269.8
Total Proved	64,413.5	22,161.0	212,200.6	1,947,541.9	858,146.8

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2019, there are no proved developed non-producing reserves for these properties. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is BCEI's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for BCEI's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil and NGL volumes, the average West Texas Intermediate spot price of $55.85 per barrel is adjusted for quality, transportation fees, and market differentials. Estimates of certain oil differentials decrease on January 1, 2024, consistent with the terms of midstream contracts, and are held constant thereafter. For gas volumes, the average Henry Hub spot price of $2.578 per MMBTU is adjusted for energy content, transportation fees, and market differentials. With the exception of the changing oil price differentials, all prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $51.22 per barrel of oil, $10.07 per barrel of NGL, and $1.436 per MCF of gas.

Operating costs used in this report are based on operating expense records of BCEI. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and BCEI's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by BCEI and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are BCEI's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the BCEI interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BCEI receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by BCEI, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from BCEI, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Benjamin W. Johnson, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2007 and has over 2 years of prior industry experience. John G. Hattner, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Benjamin W. Johnson
Benjamin W. Johnson, P.E. 124738
Vice President

Date Signed: January 30, 2020

By: /s/ John G. Hattner
John G. Hattner, P.G. 559
Senior Vice President

Date Signed: January 30, 2020

BWJ:AHA

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. 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.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – 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 Reserves – Shut-in and behind-pipe Reserves. 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 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.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *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 geologic barriers, or by 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.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* 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.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) 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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *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).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(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.

(32) *Unproved properties.* Properties with no proved reserves.