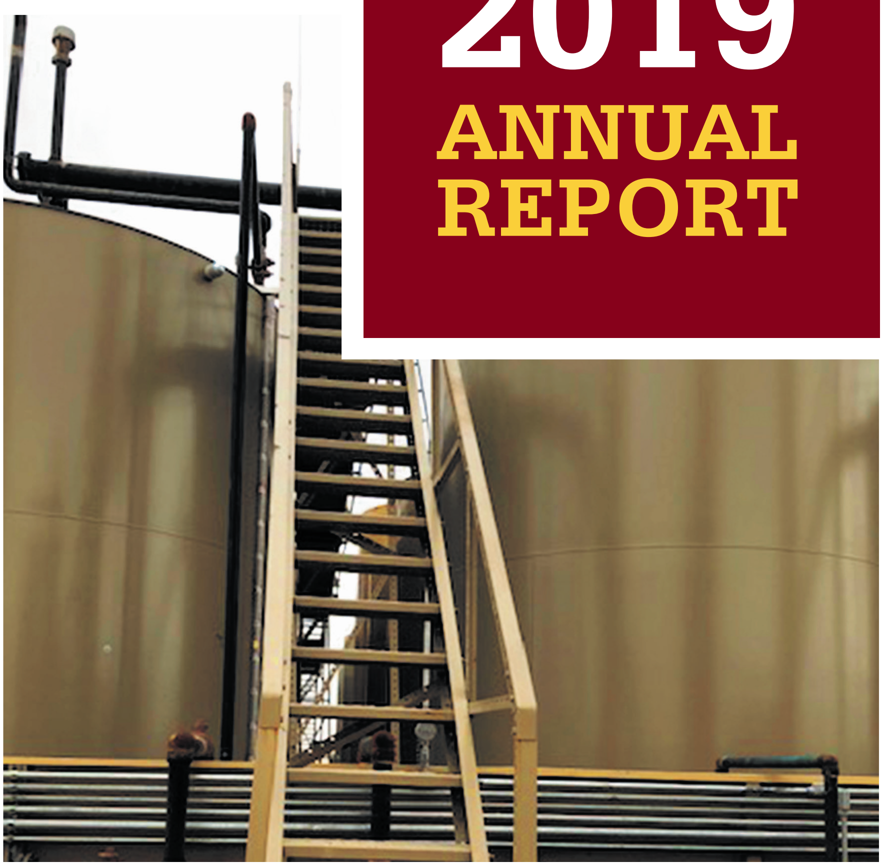
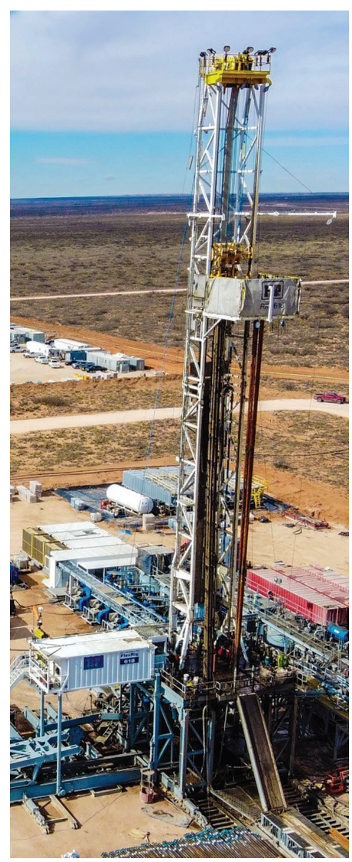
CENTENNIAL

RESOURCE DEVELOPMENT, INC

# 2019 ANNUAL REPORT





# LETTER TO SHAREHOLDERS

During 2019, Centennial continued its multi-year streak of strong operational execution. For the second consecutive year, the company exceeded its production target while staying within its original capital expenditure budget. Additionally, all but one of Centennial's original unit cost targets were achieved during the year. However, our equity value was severely affected by both low hydrocarbon prices and apathetic valuations across the entire energy sector. As we enter 2020, energy equity valuations have come under additional pressure with global oil demand concerns related to the coronavirus.

Centennial currently has one of the lowest debt-to-total capitalization ratios in the entire independent E&P equity space. Your management feels that preserving low debt is critical to a successful E&P company, and we have taken actions to maintain a conservative balance sheet during 2020 in a highly uncertain oil price environment. We plan to considerably reduce our capital expenditure budget relative to last year and also monetize our company owned saltwater disposal facilities. These actions should allow us to maintain essentially flat 2020 debt levels while exhibiting a small amount of production growth.

On the macro scale, we expect total US oil production growth to slow considerably from year-over-year growth levels of 1.6 and 1.2 million barrels per day in 2018 and 2019, respectively. In time, this US growth slowdown will allow global oil supply and demand to rebalance, ultimately strengthening oil prices. Centennial has an excellent acreage position located in arguably the best US shale oil basin. When oil rebalances, we will be ready to generate production growth from a low leverage balance sheet position with an organizational team that has a multi-year track record of exemplary execution, which we expect will lead to strong financial and shareholder returns.

Sincerely,

Mark G. Papa
Chief Executive Officer
and Chairman of the Board

# 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 001-37697

# CENTENNIAL RESOURCE DEVELOPMENT, INC.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **47-5381253** |
| (State of Incorporation) | (I.R.S. Employer Identification No.) |

**1001 Seventeenth Street, Suite 1800**

**Denver, Colorado 80202**

**(Registrant’s telephone number, including area code): (720) 499-1400**

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

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|
| Class A Common Stock, par value $0.0001 per share | CDEV | The NASDAQ Stock Market LLC |

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 the filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post 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 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 Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant as of June 28, 2019, the last business day of the registrant’s most recently completed second fiscal quarter, was approximately $1,478,769,888 based on the closing price of the shares of common stock on that date.

As of February 20, 2020, there were 276,011,045 shares of Class A Common Stock, par value $0.0001 per share, and 1,034,119 shares of Class C Common Stock, par value $0.0001 per share, outstanding.

**Documents Incorporated by Reference:**

Portions of the registrant’s definitive proxy statement for its 2020 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2019, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2019.

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## GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K, which are commonly used in the oil and natural gas industry:

*Bbl*. One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

*Bbl/d*. One Bbl per day.

*Boe*. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

*Boe/d*. One Boe per day.

*Btu*. One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one-degree Fahrenheit.

*Completion*. The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

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

*Differential*. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and location of oil or natural gas.

*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 natural gas in another reservoir.

*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 or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

*Flush production*. First yield from a flowing well during its most productive period after it is first completed and put online.

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

*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.

*LIBOR*. London Interbank Offered Rate.

*MBbl*. One thousand barrels of crude oil, condensate or NGLs.

*MBoe*. One thousand Boe.

*Mcf*. One thousand cubic feet of natural gas.

*Mcf/d*. One Mcf per day.

*MMBtu*. One million British thermal units.

*MMcf*. One million cubic feet of natural gas.

*NGL*. Natural gas liquids. These are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, that can be collectively removed from produced natural gas, separated in these substances and sold.

*NYMEX*. The New York Mercantile Exchange.

*Operator*. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.

*Proved developed reserves*. 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 with the cost of a new well.

*Proved reserves*. The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating 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 completion or recompletion.

*Realized price*. The cash market price less differentials.

*Recompletion*. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

*Reserves*. Estimated remaining quantities of oil and natural 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 natural gas or related substances to market and all permits and financing required to implement the project.

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

*Royalty interest.* An interest in an oil or gas property entitling the owner to shares of the production free of costs of exploration, development and production operations.

*Spot market price*. The cash market price without reduction for expected quality, location, transportation and demand adjustments.

*Wellbore*. The hole drilled by a drill bit that is equipped for oil and natural gas production once the well has been completed. Also called well or borehole.

*Working interest*. The interest in an oil and gas property (typically a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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

*WTI*. West Texas Intermediate is a grade of crude oil used as a benchmark in oil pricing.

## GLOSSARY OF CERTAIN OTHER TERMS

The following are definitions of certain other terms that are used in this Annual Report:

*Business Combination.* The acquisition of approximately 89% of the outstanding membership interests in CRP from the Centennial Contributors, which closed on October 11, 2016, and the other transactions contemplated by the Contribution Agreement.

*Centennial Contributors.* The legacy owners of CRP, who sold approximately 89% of the outstanding membership interests in CRP to the Company in connection with the Business Combination. As of December 31, 2019, the Centennial Contributors' ownership interest in CRP was approximately 0.4%.

*The Company, We, Our or Us.* (i) Centennial Resource Development, Inc. and its consolidated subsidiaries including CRP, following the closing of the Business Combination and (ii) Silver Run Acquisition Corporation prior to the closing of the Business Combination.

*Class A Common Stock.* Our Class A Common Stock, par value $0.0001 per share.

*Class C Common Stock.* Our Class C Common Stock, par value $0.0001 per share, which was issued to the Centennial Contributors in connection with the Business Combination.

*Contribution Agreement*. The Contribution Agreement, dated as of July 6, 2016, among the Centennial Contributors, CRP and NewCo, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, and the Joinder Agreement, dated as of October 7, 2016, by the Company.

*CRP*. Centennial Resource Production, LLC, a Delaware limited liability company.

*CRP Common Units*. The units representing common membership interests in CRP.

*GMT Acquisition.* The acquisition of certain undeveloped acreage and producing oil and natural gas properties of GMT Exploration Company LLC, which closed on June 8, 2017.

*IPO*. Our initial public offering of units, which closed on February 29, 2016.

*NewCo*. New Centennial, LLC, a Delaware limited liability company controlled by affiliates of Riverstone.

*Private Placement Warrants*. Our 8,000,000 outstanding warrants for the purchase of shares of Class A Common Stock, which were purchased by our Sponsor in a private placement simultaneously with the closing of our IPO.

*Public Warrants*. Warrants for the purchase of shares of Class A Common Stock sold as part of the Units in our IPO, all of which have been exercised or redeemed and are no longer outstanding.

*Riverstone*. Riverstone Investment Group LLC and its affiliates, including Silver Run Sponsor, LLC, a Delaware limited liability company, collectively.

*Riverstone Purchasers*. Riverstone VI Centennial QB Holdings, L.P., Riverstone Non-ECI USRPI AIV, L.P. and REL US Centennial Holdings, LLC, which are affiliates of Riverstone.

*Series B Preferred Stock*. Our Series B Preferred Stock, par value $0.0001 per share, all outstanding shares of which were converted into 26,100,000 shares of Class A Common Stock on May 25, 2017.

*Silverback.* Silverback Exploration, LLC and Silverback Operating, LLC, collectively.

*Silverback Acquisition*. The acquisition of leasehold interests and related upstream assets in Reeves County, Texas from Silverback, which closed on December 28, 2016.

V*oting common stock*. Our Class A Common Stock and Class C Common Stock.

## CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (the "Annual Report"), includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "goal," "plan," "target" 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 expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in *Item 1A. Risk Factors* in this Annual Report.

Forward-looking statements may include statements about:

- our business strategy and future drilling plans;
- our reserves and our ability to replace the reserves we produce through drilling and property acquisitions;
- our drilling prospects, inventories, projects and programs;
- our financial strategy, liquidity and capital required for our development program;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- the marketing and transportation of our oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- cost of developing our properties;
- our anticipated rate of return;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described in *Item 1A. Risk Factors* in this Annual Report.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

## PART I

## ITEMS 1 AND 2. BUSINESS AND PROPERTIES

### Overview

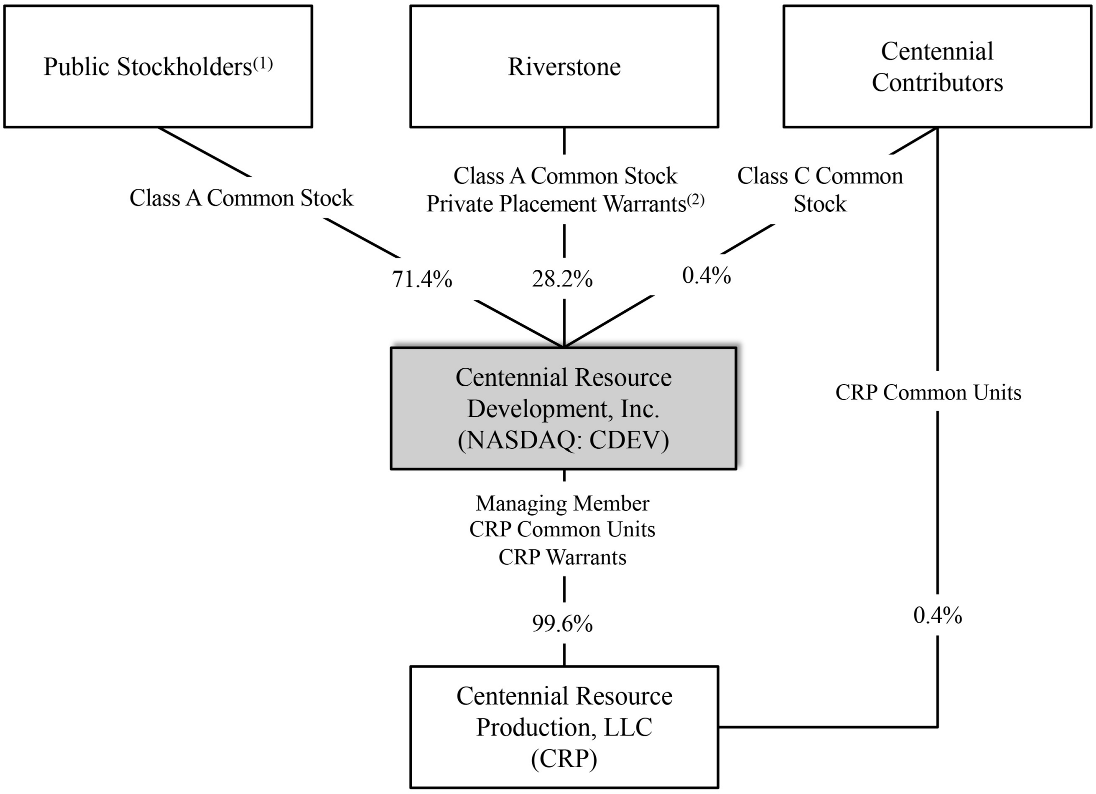
Centennial Resource Development, Inc. is an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Throughout this Annual Report, unless the context otherwise indicates, references to the "Company," "Centennial," "we," "us," or "our" refer to Centennial Resource Development, Inc. and its consolidated subsidiary, Centennial Resource Production, LLC ("CRP").

Our principal business objective is to increase shareholder value by building a premier development company focused on horizontal drilling in the Delaware Basin. We intend to grow our production and oil and natural gas reserves by developing our acreage with an increased focus on optimizing drilling and completion results, drilling extended laterals and managing costs, with an overall objective of improving our rates of return on all wells drilled and thereby funding our drilling and development capex entirely from cash flows from operations. We also intend to grow production and reserves through selective acquisitions that meet our strategic and financial objectives.

### Organizational Structure

On October 11, 2016, the acquisition of approximately 89% of the outstanding membership interests in CRP was consummated (the "Business Combination"). We currently own an approximate 99.6% membership interest in CRP due to various equity transactions.

The following diagram illustrates the current ownership structure of the company as of December 31, 2019, including the voting interests of our equity holders:

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(1) Includes NGP X US Holdings, L.P. ("NGP"), a former indirect equity owner of CRP, which also owns one share of our Series A Preferred Stock, par value $0.0001 per share (the "Series A Preferred Stock"). The Series A Preferred Stock provides NGP with the right to nominate and elect one director to the Company's board of directors, but the Series A Preferred Stock does not have any other voting rights or rights with respect to dividends except distributions in liquidation in the amount of $0.0001 per share. NGP has declined to exercise its right to nominate and elect a director since May 2019, when the director previously nominated and elected by NGP resigned.

(2) As of December 31, 2019, Riverstone owns 6,826,502 Private Placement Warrants and Mark G. Papa, our Chief Executive Officer and Chairman, owns 1,173,498. Each Private Placement Warrant is exercisable for one share of Class A Common Stock at a price of $11.50 per share and will expire on October 11, 2021 (five years after the completion of the Business Combination) or earlier upon redemption or liquidation.

**Description of Our Properties**

Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, and our properties consist of large, contiguous acreage blocks primarily in West Texas and New Mexico. As a result, we are able to efficiently develop our drilling inventory and focus on maximizing returns to our stakeholders. We have established commercial production on our acreage using horizontal drilling from nine distinct zones: the Avalon Shale, 1st Bone Spring Sand, 2nd Bone Spring Sand, 2nd Bone Spring Shale, 3rd Bone Spring Sand, 3rd Bone Spring Shale, Upper Wolfcamp A, Lower Wolfcamp A, Wolfcamp B and Wolfcamp C. We operated, a six-rig drilling program through mid-September 2019 and a five-rig program thereafter, which enabled us to complete and bring online 84 gross operated wells during the year. As of December 31, 2019, we operated 349 gross producing horizontal wells.

As of December 31, 2019, we have leased or acquired approximately 78,195 net acres, 93% of which we operate. In addition, we own 1,569 net mineral acres in the Delaware Basin. Approximately 76% of our total acreage is located in Texas, primarily Reeves County, in the southern portion of the Delaware Basin and the remaining 24% is located in New Mexico, in Lea County, in the northern portion of the Delaware Basin. Over 87% of our net acreage is held by production as of December 31, 2019. The relatively high proportion of our operated acreage that is held by production gives us significant operational control and capital spending flexibility. This allows us to execute our development program with significant control over the timing and allocation of capital expenditures and application of the optimal drilling and completion techniques to efficiently develop our resource base. Our development drilling plan is comprised exclusively of horizontal drilling with an ongoing focus on optimizing completions, improving drilling results and managing costs.

**Proved Oil and Gas Reserves**

Reserve estimates are inherently imprecise, and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The pre-tax PV 10% amounts shown in the following table are not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated, due to a number of factors. The following table should be read along with *Item 1A. Risk Factors* in this Annual Report.

The following table summarizes estimated proved reserves, pre-tax PV 10%, and standardized measure of discounted future cash flows as of the periods indicated:

| | December 31, 2019 | December 31, 2018 | December 31, 2017 |
|---|---|---|---|
| **Proved developed reserves:** | | | |
| Oil (MBbls) | 74,842 | 63,317 | 41,786 |
| Natural gas (MMcf) | 237,791 | 180,542 | 126,065 |
| NGL (MBbls) | 32,743 | 23,093 | 12,133 |
| Total proved developed reserves (MBoe)[1] | 147,216 | 116,500 | 74,929 |
| **Proved undeveloped reserves:** | | | |
| Oil (MBbls) | 75,317 | 79,449 | 59,147 |
| Natural gas (MMcf) | 264,639 | 222,310 | 201,147 |
| NGL (MBbls) | 34,499 | 28,825 | 18,853 |
| Total proved undeveloped reserves (MBoe)[1] | 153,923 | 145,326 | 111,525 |
| **Total proved reserves:** | | | |
| Oil (MBbls) | 150,159 | 142,766 | 100,933 |
| Natural gas (MMcf) | 502,430 | 402,852 | 327,212 |
| NGL (MBbls) | 67,242 | 51,918 | 30,986 |
| Total proved reserves (MBoe)[1] | 301,139 | 261,826 | 186,454 |
| | | | |
| Proved developed reserves % | 49% | 44% | 40% |
| Proved undeveloped reserves % | 51% | 56% | 60% |
| | | | |
| **Reserve values (in millions):** | | | |
| Standard measure of discounted future net cash flows | $ 2,062.4 | $ 2,479.9 | $ 1,503.3 |
| Discounted future income tax expense | 135.5 | 499.6 | 244.8 |
| Total proved pre-tax PV 10% [2] | $ 2,197.9 | $ 2,979.5 | $ 1,748.1 |

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(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

(2) Total proved pre-tax PV 10% (“Pre-tax PV 10%”) may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (the ‘‘Standardized Measure’’), which is the most directly comparable U.S. generally accepted accounting principles (“GAAP”) financial measure. Pre-tax PV 10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe Pre-tax PV 10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our Pre-tax PV 10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, Pre-tax PV 10% is not a substitute for the Standardized Measure. Our Pre-tax PV 10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

*Proved Undeveloped Reserves.* Our proved undeveloped ("PUD") reserves increased by 8.6 MMBoe on a net basis from December 31, 2018 to December 31, 2019, and the following table provides a reconciliation of the changes to our PUD reserves that occurred during the year:

| | 2019 |
|---|---|
| | (MBoe) |
| **Proved undeveloped reserves at January 1,** | 145,326 |
| Transferred to proved developed reserves | (28,398) |
| Revisions to previous estimates | 6,487 |
| Extensions and discoveries | 30,508 |
| **Proved undeveloped reserves at December 31,** | 153,923 |

During 2019, we spent $295.7 million in capital expenditures to convert 28.4 MMBoe of PUD reserves to proved developed reserves. We added 30.5 MMBoe of PUD reserves from extensions and discoveries during the year primarily due to new PUD locations that resulted from our 2019 drilling program, the majority of which were in the Upper Wolfcamp A formation in our Texas position and in the 2nd Bone Spring formations in our New Mexico acreage. Revisions to previous estimates added 6.5 MMBoe net PUD reserves and consisted of 21.4 MMBoe of upward revisions partially related to well performance revisions to reflect higher gas and NGL yields on older wells, which in turn increased total estimated ultimate recovery ("EURs") for most of our PUD locations. These upward revisions were partially offset by 14.9 MMBoe of negative revisions for downward pricing adjustments (7.5 MMBoe) and PUD locations that were reclassified to unproven reserves due to: (i) such locations no longer being a part of our active development program, and (ii) 1.0 MMBoe removed for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules. All of our PUD locations are scheduled to be drilled within five years of their initial booking. Our PUD to proved developed reserves conversion rate was 23% in 2019.

For additional information and for a discussion of material changes on our total proved reserves, see *Supplemental Information About Oil & Natural Gas Producing Activities*, Item 8. Financial Statements and Supplementary Data of this Annual Report.

## Preparation of Reserve Estimates

Our proved reserves are estimated by an independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Reserve estimates are prepared in accordance with the definitions and regulations of the SEC and the Financial Accounting Standards Board (the "FASB") using a deterministic method, which includes decline curve analysis, production performance analysis, offset analogies, and in some cases a combination of these methodologies.

### *Controls over Reserve Estimation*

We maintain adequate and effective internal controls over the reserve estimation process and the underlying data which the reserve estimates are based upon. Our reserves estimation process is coordinated by our internal reserves department, which consists of qualified petroleum engineers, and is overseen by our Vice President of Reservoir Engineering. Reserve information, including models and other technical data, are stored on a secured database on our network. Certain non-technical inputs used in the reserves estimation process such as ownership interest percentages, oil and natural gas production, commodity prices, price differentials, operating and development costs and plug and abandonment estimates are obtained by other departments and are subject to our internal control process. Annually, our internal reserves department prepares a preliminary reserve database and meets with NSAI to discuss the assumptions and methods to be used in the year-end proved reserve estimation process and to review field performance and our future development plans. Following this review, the reserve database and supporting data is furnished to NSAI for their independent estimates and final report.

### *Qualifications of Responsible Technical Persons*

Our Vice President of Reservoir Engineering, Jeff Thompson, is responsible for overseeing the preparation of the reserves estimates. Mr. Thompson has held this position at Centennial since July 2017 and has over 10 years of relevant experience in reservoir engineering and reserve estimation. He holds a Bachelor of Science degree in petroleum engineering from the University of Oklahoma and is a Registered Professional Engineer in Oklahoma and member of the Society of Petroleum Engineers.

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 reserve report incorporated herein are Mr. Neil H. Little and Mr. Mike K. Norton. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. He graduated from Rice University with a Bachelor of Science Degree in Chemical Engineering and from University of Houston with a Master of Business Administration Degree. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441), has been practicing petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. He graduated from Texas A&M University with a Bachelor of Science Degree in Geology. 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 reserve definitions and guidelines.

## Production

The following table sets forth information regarding net production of oil, natural gas and NGLs, and certain price and cost information for each of the periods indicated:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| **Net Production:** | | | |
| Oil (MBbls) | 15,582 | 12,679 | 6,944 |
| Natural gas (MMcf) | 41,703 | 31,707 | 17,754 |
| NGLs (MBbls) | 5,234 | 4,332 | 1,678 |
| Total (MBoe) [(1)] | 27,766 | 22,295 | 11,630 |
| **Average realized prices (excluding effect of hedges):** | | | |
| Oil (per Bbl) | $ 52.02 | $ 55.98 | $ 48.17 |
| Natural gas (per Mcf) | 1.07 | 1.97 | 2.75 |
| NGL (per Bbl) | 17.03 | 27.45 | 26.28 |
| Total per BOE [(1)] | $ 34.01 | $ 39.97 | $ 36.96 |
| **Operating costs per Boe:** | | | |
| Lease operating expenses | $ 5.26 | $ 3.74 | $ 3.55 |
| Severance and ad valorem taxes | 2.28 | 2.54 | 1.99 |
| Gathering, processing and transportation expenses | 2.62 | 2.58 | 2.95 |

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

## Productive Wells

As of December 31, 2019, we owned an approximate 76% average working interest in 484 gross (368 net) productive wells. Our wells are primarily oil wells (467 gross/354 net productive oil wells) that produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

## Acreage

The following table sets forth information as of December 31, 2019 relating to our gross and net developed and undeveloped leasehold acreage. Developed acreage consists of acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

| Developed Acreage[(3)] | | Undeveloped Acreage[(3)] | | Total Acreage[(3)] | |
|---|---|---|---|---|---|
| Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] |
| 52,640 | 40,626 | 45,001 | 37,569 | 97,641 | 78,195 |

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(3) Does not include our 1,569 net mineral acres.

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2019, that will expire over the next five years unless production is established within the spacing units covering the acreage, the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates, or pursuant to other terms of the lease agreements.

| 2020 | | 2021 | | 2022 | | 2023 | | 2024 | |
|---|---|---|---|---|---|---|---|---|---|
| Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| 4,936 | 3,162 | 6,363 | 3,750 | 5,458 | 2,118 | — | — | 1,039 | 1,039 |

## Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells placed on production, for the periods indicated. Productive wells are exploratory, development or extension wells that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are exploratory, development or extension wells that prove to be incapable of producing hydrocarbons in sufficient quantities to justify incurring the costs associated with completion as an oil or gas well.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2019 | | 2018 | | 2017 | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Development Wells:** | | | | | | |
| Productive(1) | 84 | 73.6 | 80 | 72.4 | 69 | 65.2 |
| Dry(2) | 2 | 2.0 | — | — | 1 | 1.0 |
| | 86 | 75.6 | 80 | 72.4 | 70 | 66.2 |
| **Exploratory Wells:** | | | | | | |
| Productive(1) | — | — | — | — | 1 | 1.0 |
| Dry | — | — | — | — | 1 | 1.0 |
| | — | — | — | — | 2 | 2.0 |
| Total | 86 | 75.6 | 80 | 72.4 | 72 | 68.2 |

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

(2) The dry hole category includes wells that were unsuccessful due to mechanical issues during drilling.

As of December 31, 2019, we had 15 gross (14.3 net) operated wells in the process of drilling, completing or waiting on completion.

## Delivery Commitments

The table below summarizes our firm sales agreements for crude oil and natural gas, both of which provide for gross firm sales over the contractual terms:

| | Oil Volume Commitments [1] [2] | | Gas Volume Commitments [1] [3] | |
|---|---|---|---|---|
| **Period** | **Total (Bbl)** | **Daily (Bbls/d)** | **Total (MMBtu)** | **Daily (MMBtu/d)** |
| 2020 | 27,460,000 | 75,000 | 30,800,000 | 84,200 |
| 2021 | 32,247,000 | 88,300 | 14,600,000 | 40,000 |
| 2022 | 36,500,000 | 100,000 | 12,160,000 | 40,000 |
| 2023 | 38,325,000 | 105,000 | — | — |
| 2024 | 10,950,000 | 30,000 | — | — |
| Total | 145,482,000 | | 57,560,000 | |

(1) Above volumes represent the total gross volumes we are required to deliver per the agreements, which is not comparable to our net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation* in this Annual Report as amounts therein are reflected net of all royalties, overriding royalties and production due to others.

(2) We are only required to physically deliver 30,000 Bbls/d of the total committed volumes of crude oil during the contractual years 2020 through 2024, and if these physical delivery commitments are not met, a financial obligation would arise. Failure to deliver the remainder of the committed volumes of crude oil under these agreements could result in a reduction of our future firm takeaway capacity at the purchasers' discretion in accordance with the terms of the agreements.

(3) We are not required to physically deliver these volumes of natural gas over the contractual terms of the agreements. However, if the committed firm sales are not met and the purchaser incurs financial damages, we may be required to pay for differences between the contracted prices and current market prices for replacement volumes bought by the purchaser, and the purchaser may also require us to provide additional financial guaranty in accordance with the terms of the agreements.

We believe our current production and reserves are sufficient to fulfill these physical delivery commitments; however, production under the agreements is not tied to any specific property. Therefore, if our production is not sufficient to satisfy the firm delivery commitments above, we believe we can purchase sufficient volumes in the market at index-related prices to satisfy our commitments. See also *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations*, in this Annual Report for discussion of our firm transportation commitments related to natural gas deliveries.

## Title to Properties

We believe that we have satisfactory title to substantially all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, working and other outstanding interests customary in the industry. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

## Marketing and Customers

We market the majority of the production from properties we operate on account of both ourselves and that of the other working interest owners in these properties. We generally sell our oil, natural gas and NGL production to purchasers at prevailing market prices, and the majority of our revenue contracts have terms greater than twelve months.

We normally sell production to a relatively small number of customers, as is customary in our business. The tables below present percentages by purchaser that accounted for 10% or more of our net revenues for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2019** | **2018** | **2017** |
| BP America | 37% | 18% | 16% |
| ExxonMobil Oil Corporation | 26% | —% | —% |
| Shell Trading (US) Company | 11% | 19% | 33% |
| Eagleclaw Midstream Ventures, LLC | 8% | 12% | 14% |

During these periods, no other purchaser accounted for 10% or more of our net revenues. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term. However, since crude oil and natural gas are fungible products with well-established markets and numerous purchasers and are based on current demand for oil and natural gas, we believe that the loss of any major purchaser would not have a material adverse effect on our financial condition or results of operations.

**Competition**

The oil and natural gas industry is a highly competitive environment. We compete with both major integrated and other independent oil and natural gas companies in all aspects of our business including exploring, developing and operating our properties as well as transporting and marketing our production. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect the supply and demand for oil and natural gas production, such as price fluctuations (including basis differentials), domestic and foreign political conditions, weather conditions, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources, including wind, solar and electric power. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

**Transportation**

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the areas of our production. The majority of our oil production is sold at the lease as it enters third-party gathering pipelines. The purchaser then transports the oil by pipeline or truck to a tank farm, another pipeline or a refinery. Our natural gas is generally transported by gathering lines from the wellhead to a central delivery point and is then gathered by third-party lines to a gas processing facility.

**Regulation of the Oil and Natural Gas Industry**

Our operations are subject to extensive federal, state and local laws and regulations. All of the jurisdictions in which we own or operate producing properties have statutory provisions regulating the development and production of oil and natural gas, including, but not limited to, 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. Our operations are also subject to various conservation laws and regulations including, but not limited to, the 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 crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and 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. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings affecting the oil and natural gas industry are regularly considered by Congress, the states, regulatory authorities, including the Federal Energy Regulatory Commission (“FERC”), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and 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 environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

***Regulation of Production of Oil and Natural Gas***

The production of oil, natural gas and NGLs 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 permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in New Mexico and Texas, which regulate drilling and operating activities by, among other things, requiring 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. The laws of New Mexico and Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, natural gas and NGLs that we can produce from our wells and to limit the number of wells or the locations where we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, New Mexico and Texas impose a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within their jurisdiction.

Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, and as a result we do not expect compliance with such regulatory requirements to affect our operations in any way that is of material difference from our competitors who are similarly situated. However, the failure to comply with these rules and regulations can result in substantial penalties.

***Regulation of Sales and Transportation of Oil***

Sales of oil, condensate and NGLs from our producing wells are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Sales of oil are affected by the availability, terms and conditions and cost of transportation services. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates the transportation in interstate commerce of crude oil, petroleum products, NGLs and other forms of liquid fuel under the Interstate Commerce Act.

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. We rely on third-party pipeline systems to transport the majority of crude oil produced by ours wells. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies 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 oil producers and marketers with which we compete.

***Regulation of Transportation and Sales of Natural Gas***

Historically, the transportation and sale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government 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 of 1978 (the “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 of 1938 (the “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.

The federal Energy Policy Act of 2005 (the “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 amended the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provided FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increased FERC’s civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. In January 2020, FERC issued a final rule increasing its maximum civil penalty authority under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of $1,291,894 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 or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) 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, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

We are required to observe such anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and those enforced by the US Commodity Futures Trading Commission (the “CFTC”) under the Commodity Exchange Act, as amended (the “CEA”) and CFTC regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce, as well as the market for financial instruments on such commodity, such as futures, options and swaps. 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. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Natural gas gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states. Section 1(b) of the NGA exempts companies that provide natural gas gathering services from regulation by FERC as a “natural gas company” under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC’s determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, or vice versa, and depending on the scope of that decision, our costs of delivering gas to point-of-sale locations may increase. 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. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

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 any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those 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 FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action that FERC or state regulatory bodies 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 and marketers with which we compete.

***Regulation of Environmental and Occupational Safety and Health Matters***

Our operations are subject to stringent federal, state and local laws and regulations governing the occupational safety and health aspects of our operations, the discharge of materials into the environment, and protection of the environment and natural resources (including threatened and endangered species and their habitats). Numerous governmental entities, including the U.S. Environmental Protection Agency (the “EPA”) and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things, (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentrations of various substances that can be released into the environment or injected into formations in connection with drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; (iv) require remedial measures to prevent or mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

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

***Hazardous Substances and Handling Wastes***

The Resource Conservation and Recovery Act (“RCRA”) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and nonhazardous solid wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and other wastes associated with the exploration, development and production of oil, natural gas and NGLs, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA’s less stringent nonhazardous solid waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree required the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes, or to sign a determination that revision of the regulations is not necessary. After undertaking its review, the EPA concluded in 2019 that it does not need to regulate exploration and production waste, and specifically "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy." The EPA concluded that states are adequately regulating exploration and production waste under the Subtitle D provisions of RCRA. However, any such change in the future could result in an increase in our, as well as the oil, natural gas and NGL exploration and production industry’s, costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we may generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or the legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners or operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment, and to seek to recover from the responsible classes of persons the costs they incur. In addition, 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 may generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease or operate numerous properties that have been used for oil, natural gas and NGL exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

***Water Discharges***

The Clean Water Act (the “CWA”) and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other CWA requirements and analogous state laws and regulations.

The CWA also prohibits the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by permit. The EPA and the U.S. Army Corps of Engineers issued final rules attempting to clarify the federal jurisdictional reach over Waters of the United States in 2015 (the “WOTUS rule”). However, in 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to review the WOTUS rule and, if the agencies’ reviews find that the rule does not meet the executive order’s goal of promoting economic growth while reducing regulatory uncertainty, to initiate a new rulemaking to repeal or revise the rule. Pursuant to the executive order, in June 2017, the EPA and U.S. Army Corps of Engineers formally proposed to rescind the WOTUS rule. In January 2018, the EPA and the U.S. Army Corps of Engineers finalized a rule that would delay applicability of the WOTUS rule for two years, but a federal judge barred the agencies’ suspension of the rule in August 2018. Separately, a federal court in Georgia enjoined implementation of the rule in 11 states. However, in December 2018, the EPA and the U.S. Army Corps of Engineers released a proposed rule that would replace the WOTUS rule and significantly reduce the waters subject to federal regulation under the CWA. The EPA and the U.S. Army Corps of Engineers formally repealed the WOTUS rule in September 2019. In January 2020, the Trump administration published a final replacement rule, called the Navigable Waters Protection Rule, that purports to expressly define which categories of water may be federally regulated under the CWA. The Navigable Waters Protection Rule is set to take effect 60 days from publication of the replacement rule in the Federal Register. Legal challenges to the Navigable Waters Protection Rule are expected. As such, uncertainty remains with respect to future implementation of the rule.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (the “OPA”), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

***Subsurface Injections***

In the course of our operations, we produce water in addition to natural gas, crude oil and NGLs. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control (the “UIC”) program established under the federal Safe Drinking Water Act (the “SDWA”) and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near below-ground disposal wells used for the injection of natural gas- and oil-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety. These seismic events have also led to an increase in tort lawsuits filed against exploration and production companies, as well as the owners of underground injection wells. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability; however, these costs are commonly incurred by all oil, natural gas and NGL producers, and we do not believe that the costs associated with the disposal of produced water will affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

***Air Emissions***

The federal Clean Air Act (the “CAA”) and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of our projects. Recently, there has been increased regulation with respect to air emissions from the oil and natural gas sector. For example, the EPA promulgated rules in 2012 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 a separate set of requirements to address certain hazardous air pollutants frequently associated with oil and natural gas production and processing activities pursuant to the National Emissions Standards for Hazardous Air Pollutants program.

In June 2016, the EPA published final rules establishing new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA’s final rules include NSPS to limit methane emissions from equipment and processes across the oil and natural gas source category. The rules also extend limitations on volatile organic compound (“VOC”) emissions to sources that were unregulated under the previous NSPS at Subpart OOOO. Affected methane and VOC sources include hydraulically fractured (or re-fractured) oil and natural gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. Several states and industry groups have filed suit before the U.S. Court of Appeals for the D.C. Circuit (the “D.C. Circuit”) challenging the EPA’s implementation of the methane rule and the EPA’s legal authority to issue the methane rules. However, in April 2017, the EPA announced that it will review its methane rule for new, modified and reconstructed sources and to initiate reconsideration proceedings to potentially revise or rescind portions of the rule. In addition, the EPA issued a stay of the June 3, 2017 compliance date applicable to fugitive emissions monitoring requirements for 90 days. In July 2017, the D.C. Circuit found that the EPA's decision to issue the stay was not permissible under the CAA and vacated the stay, but subsequently issued a revised opinion allowing the agency to stay implementation of the rule for two weeks. However, in June 2017, the EPA issued a proposed rulemaking to stay the requirements of Subpart OOOOa for a period of two years and to revisit implementation of Subpart OOOOa in its entirety. In September 2018, the EPA proposed amendments to the 2016 rules that would reduce the 2016 rules' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 methane requirements and EPA's attempt to delay the implementation of the rule. Further, in August 2019, the EPA proposed two options for rescinding the Subpart OOOOa standards. Under the EPA's preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for VOCs, and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general). As a result of these developments, future implementation of the standards is uncertain at this time.

The Bureau of Land Management (the "BLM") also finalized rules (the "BLM methane rule") in November 2016 that seek to limit methane emissions from exploration and production activities on federal lands by imposing limitations on venting and flaring of natural gas, as well as requirements for the implementation of leak detection and repair programs for certain processes and equipment. After attempts by the Trump administration to delay implementation of the BLM methane rule, and legal challenges both to the BLM methane rule and the delays, the BLM issued a final rule in September 2018 rescinding many of the provisions of the 2016 BLM methane rule, including the requirement to implement leak detection and repair programs, and imposing certain new requirements in a manner the BLM considered would reduce unnecessary compliance obligations on the industry.

The EPA also finalized separate rules under the CAA in June 2016 regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In addition, in October 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standards for ground-level ozone from the current standard of 75 parts per billion ("ppb") for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. The final rule became effective on December 28, 2015. The EPA issued its anticipated area designations in November and December 2017. States are expected to implement more stringent permitting and pollution control requirements as a result of this new final rule, which could apply to our operations.

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

***Regulation of GHG Emissions***

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") preconstruction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards that will typically be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from large GHG emission sources in the United States, including certain onshore and offshore natural gas, oil and NGL production sources, which include certain of our operations. As discussed above, federal regulatory action regarding GHG emissions from the oil and gas sector has focused on methane emissions; however, federal implementation of the finalized 2016 methane rule is uncertain at this time (as also discussed above).

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, no significant legislation has been adopted at the federal level. In the absence of such federal climate legislation, a number of state and regional cap-and-trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will take to achieve its GHG emissions targets. The Paris Agreement entered into force on November 4, 2016 upon achieving its threshold for ratification by signatory countries. A long-term goal of the Paris Agreement is to limit global warming to below two degrees Celsius by 2100 from temperatures in the pre-industrial era. However, the Paris Agreement does not impose any binding obligations on its participants. In June 2017, President Trump stated that the United States intends to withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of its intent to withdraw from the Paris Agreement unless it is renegotiated, and in November 2019 formally initiated the withdrawal process, which would result in an effective exit date of November 2020. The United States adherence to the exit process is uncertain and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

Although it is not possible at this time to predict how new laws or regulations that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting 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, as well as delay or restrict our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the natural gas, oil and NGLs we produce and lower the value of our reserves. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

***Hydraulic Fracturing Activities***

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil, natural gas and NGLs from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016, establishing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting (which are subject to revision, as discussed above); published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication version of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act ("TSCA") reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in March 2015, the BLM adopted rules establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands. In June 2016, a federal district court judge in Wyoming struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That ruling was appealed, but in September 2017 the U.S. Court of Appeals for the Tenth Circuit dismissed the appeal and remanded with directions to vacate the lower court's opinion, leaving the final rule in place. However, following the issuance of an executive order by President Trump to review rules related to the energy industry, the BLM initiated a rulemaking to rescind the final rule in December 2017. Shortly after the final rulemaking was issued, the state of California and several environmental groups filed lawsuits against the BLM, the Secretary of the Interior, and the Assistant Secretary for Land and Minerals Management, seeking an injunction and a declaration that the repeal violated numerous federal statutes. After the suits were filed, multiple industry groups and the state of Wyoming sought to intervene and transfer the case to federal court in Wyoming, which decided the initial legal challenge to the Obama administration's fracking regulations. A hearing was held in January 2020 to consider a motion for summary judgment in the case. However, those legal challenges are still pending. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under certain limited circumstances."

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, the regulation of hydraulic fracturing has continued at the state level. For example, Wyoming has promulgated rules related to the public disclosure of substances used in hydraulic fluid, testing requirements for water wells near drilling sites and leak detection and repair requirements for fugitive emissions from oil and gas production facilities.

In the event that a new, federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

***Activities on Federal Lands and State Lands***

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, are frequently subject to permitting delays. Operations on these lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an

Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. We currently have exploration, development and production activities on federal lands. Our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of natural gas, oil and NGL projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in the Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

In addition, the New Mexico state legislature recently considered House Bill 206, which, if passed, would have enacted an Environmental Review Act comparable to NEPA. Specifically, the Environmental Review Act would require state governmental agencies at all levels to consider the qualitative, technical and economic factors relating to a project that may impact public health, ecosystems and the environment, the long-term as well as short-term benefits and costs of the proposed project, the cumulative impacts of the proposed project, and reasonable alternatives to proposed actions affecting the environment, communities or public health. If reconsidered and enacted in the future, the process contemplated by the Environmental Review Act has the potential, like NEPA, to delay or limit, or increase the cost of, the development of natural gas, oil and NGL projects in New Mexico, which costs could be substantial.

***ESA and Migratory Birds***

The federal Endangered Species Act (“ESA”) and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of a 2011 settlement agreement, the U.S. Fish and Wildlife Service (the “FWS”) was required to make a determination on listing of numerous species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The FWS did not meet that deadline. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases. In addition, the federal government recently has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after migratory birds were found dead near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

***OSHA***

We are subject to the requirements of the Occupational Safety and Health Act (“OSHA”) and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, OSHA’s hazard communication standard, the Emergency Planning and Community Right-to-Know Act, comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

***Related Permits and Authorizations***

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other activities and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

***Related Insurance***

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our development activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

**Employees**

As of December 31, 2019, we had 195 full-time employees. We hire independent contractors on an as needed basis and have no collective bargaining agreements with our employees.

**Offices**

Our principal executive offices are located at 1001 Seventeenth Street, Suite 1800, Denver, Colorado 80202, and our telephone number is (720) 499-1400. We also have office space in Midland, Texas; Sugar Land, Texas; Pecos, Texas; and Jal, New Mexico.

**Available Information**

Our internet website address is www.cdevinc.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. Information on our website is not incorporated by reference into this Annual Report and should not be considered part of this document.

The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at www.sec.gov.

## ITEM 1A. RISK FACTORS

*The nature of our business activities subjects us to certain hazards and risks. The following risks and uncertainties, together with other information set forth in this Annual Report, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.*

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

***Oil, natural gas and NGL prices are volatile. A sustained period of low commodity prices for oil, natural gas and NGLs could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.***

The prices we receive for our oil, natural gas and NGLs production heavily influence our revenue, cash flows, profitability, access to capital, future rate of growth and carrying value of our properties. Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs and market uncertainty. Historically, oil, natural gas and NGL prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas and NGLs;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries (“OPEC”), its members and other state-controlled oil companies relating to oil price and production controls;
- political, economic and other conditions that affect perceived demand for oil, natural gas and NGLs, including trade tensions between the U.S. and other countries and global health epidemics and concerns;
- the level of global exploration, development and production;
- the level of global inventories;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the availability of refining and storage capacity;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- terrorist attacks targeting oil and natural gas related facilities and infrastructure;
- technological advances affecting fuel economy, energy supply and energy consumption;
- the price and availability of alternative fuels;
- laws, regulations and taxes in the U.S. and in foreign jurisdictions that decrease the demand for oil, natural gas and NGLs;
- shareholder activism or activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize emissions of carbon dioxide and methane GHGs;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. From 2015 through 2019, the WTI spot price for oil averaged $53.05 per Bbl, which is down substantially from the $60.21 average for the prior five-year period. The Henry Hub average spot price from 2015 through 2019 of $2.77 per MMBtu similarly declined from $3.12 per MMBtu, which was the average for the prior five-year period. Likewise, NGLs, which are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, have suffered significant recent price declines.

A sustained or further extended decline in commodity prices may result in a shortfall in our expected cash flows and require us to reduce capital spending or borrow funds to cover any such shortfall. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Also, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods of low commodity prices for oil and natural gas and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone, moderate or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to moderate or curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a sustained or further extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

***Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.***

The oil and natural gas industry is capital-intensive. We make and expect to continue to make substantial capital expenditures related to development and acquisition projects. We have funded our capital expenditures with cash generated by operations, borrowings under CRP’s revolving credit facility and the net proceeds from CRP’s issuance of senior notes. We intend to finance our capital expenditures with cash flow from operations, proceeds received from the contemplated divestiture of our saltwater disposal assets, borrowings under CRP’s revolving credit facility and proceeds from offerings of debt and equity securities. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- CRP’s ability to borrow under its revolving credit facility and the ability to access the capital markets.

If our revenues or the borrowing base under CRP’s revolving credit facility decrease as a result of lower oil, natural gas and NGL 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 at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under CRP’s revolving credit facility are 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 properties. This, in turn, could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

***Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.***

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include the following:

- landing a wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- spacing the wells appropriately to maximize production rates and recoverable reserves;
- running our casing the entire length of the wellbore; and

- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations;
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage; and
- the ability to prevent unintentional communication with other wells.

In addition, certain of the new techniques we are adopting, such as infilling drilling and multi-well pad drilling, may cause irregularities or interruptions in production due, in the case of infill drilling, to offset wells being shut-in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as anticipated, and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

***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 development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to develop or purchase prospects 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 the risk factor "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain.

Further, many factors may curtail, delay, cancel or otherwise negatively impact our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations resulting from wastewater disposal, emission of GHGs and limitations on hydraulic fracturing;
- lack of available capacity on interconnecting transmission pipelines;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, qualified personnel, water or sand for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in the construction of gathering facilities;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

***Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in 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 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 our reserves. In order to prepare reserve estimates, we must project production rates and 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.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than our estimates and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. Our estimated proved reserves as of December 31, 2019, and related standardized measure were calculated under rules of the SEC using twelve-month trailing average benchmark prices of $52.19 per barrel of oil (WTI Posted) and $2.58 per MMBtu (Henry Hub spot), which may be substantially higher or lower than the available spot prices in 2020. For example, if the crude oil and natural gas prices used in our year-end reserve estimates were to increase or decrease by 10%, our proved reserve quantities at December 31, 2019 would increase by 4.4 MMBoe (1%) or decrease by 22.3 MMBoe (7%), respectively, and the pre-tax PV10% of our proved reserves would increase by $509.4 million (23%) or decrease by $503.1 million (23%), respectively.

***We will not be the operator on all of our acreage or drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.***

As of December 31, 2019, we have leased or acquired approximately 78,195 net acres, approximately 93% of which we operate. As of December 31, 2019, we operated 349 gross producing horizontal wells. We will have limited ability to exercise influence over the operations of the drilling locations operated by our partners, and there is the risk that our partners may at any time have economic, business or legal interests or goals that are inconsistent with ours. Furthermore, the success and timing of development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- the approval of other participants in drilling wells;
- the selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations and associated costs of some of our drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activities.

***Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.***

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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

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

***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 primary term is extended through continuous drilling provisions or the leases are renewed.***

As of December 31, 2019, over 87% of our total net acreage was held by production. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. Some of our leases also expire as to certain depths if continuous drilling obligations are not met. If our leases expire in whole or in part and we are unable to renew the leases, we will lose the right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

***Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.***

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in Texas in past years. These drought conditions have led some local water districts to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

***Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to dispose of or recycle the saltwater we use economically and in an environmentally safe manner.***

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle our produced water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water and result in the production of waste water. For example, the hydraulic fracturing process, which we employ to produce commercial quantities of crude oil, natural gas and NGLs, requires the use and disposal of significant quantities of water. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought) could materially and adversely impact our operations. Severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdictions for drilling and hydraulic fracturing in order to protect local water supply. If we are unable to obtain water to use in our operations from local sources, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and gas production operations, including produced water, directly or through the use of third party vendors. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection of produced water resulting from oil and gas activities, which has led to increased public and governmental scrutiny of injection safety. In response to concerns regarding induced seismicity, regulators in Texas have adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity.

Another consequence of water disposal activities and seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells or commercial disposal wells to dispose of produced water. Increased regulation and attention given to water disposal and induced seismicity could also lead to greater opposition, including litigation, to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in limitations on disposal well volumes, disposal rates and pressures or locations, require us or our vendors to shut down or curtail the injection into disposal wells, or cause delays, interruptions or termination of our operations, which events could have a material adverse effect on our business, financial condition and results of operations.

***Our producing properties are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, making us vulnerable to risks associated with operating in a single geographic area.***

Our producing properties are geographically concentrated in the Delaware Basin, a sub-basin of the Permian Basin, primarily in West Texas and New Mexico. At December 31, 2019, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

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

We enter into derivative instrument contracts for a portion of our oil and natural gas production from time to time. As of December 31, 2019, we had entered into basis swaps through 2020 covering a total of 1,098 MBbls of our projected oil production at a weighted average differential of $0.67 per Bbl. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments 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 contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of CRP’s borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

***The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.***

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is generally transported from the wellhead by gathering systems that are either owned by us or third-party midstream companies, although some of our oil is initially transported by truck to a transportation facility. Our natural gas production is generally transported by gathering lines that are owned either by us or third-party midstream companies from the wellhead to a gas processing facility. In general, we do not control these trucks and other third-party transportation facilities and our access to them may be limited or denied. In some instances, we have contractual guarantees relating to the transportation of our production through firm transportation arrangements, but third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents or other reasons. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or third-party midstream companies or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

***We have entered into multi-year agreements with some of our suppliers, service providers and the purchasers of our oil and natural gas, which contain minimum volume commitments. Any failure by us to satisfy the minimum volume commitments could lead to contractual penalties that could adversely affect our results of operations and financial position.***

We have entered into certain multi-year supply and service agreements, including contracts for drilling rigs, water disposal agreements and purchase agreements relating to frac and sand products. We also have various multi-year agreements that relate to the sale, transportation or gathering of our oil and natural gas. Some of these agreements contain minimum volume commitments that we must satisfy or contractual penalties in form of volume deficiencies or other remedies may apply. As of December 31, 2019, our aggregate long-term contractual obligation under these agreements was $46.1 million, which represents the gross minimum obligation but does not include amounts that may be due under certain contracts that contain variable pricing or volumetric components as the future obligations cannot be determined. Further information about these agreements can be found at *Note 13—Commitments and Contingencies*, Item 8. Financial Statements and Supplementary Data in this Annual Report. Any failure by us to satisfy the minimum volume commitments in these agreements could adversely affect our results of operations and financial position.

***We may incur losses as a result of title defects in the properties in which we invest.***

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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

As of December 31, 2019, 51% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs 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 PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

***If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.***

Accounting guidance requires that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and 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, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. Over the last several years, commodity prices have declined significantly. A sustained or further extended decline in commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

***Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.***

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flows and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

***Conservation measures and technological advances could reduce demand for oil and natural gas.***

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, results of operations and cash flows.

***We depend upon a small number of significant purchasers for the sale of most of our oil, natural gas and NGL production.***

We normally sell production to a relatively small number of customers, as is customary in our business. See *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, Item 8. Financial Statements and Supplementary Data in this Annual Report for significant purchasers that accounted for more than 10% of our revenues for the years ended December 31, 2019, 2018 and 2017. The loss of any of our major purchasers could materially and adversely affect our revenues in the near-term.

***Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.***

Our operations are subject to stringent, complex and evolving federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our 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. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. In the states of New Mexico and Texas, as an example, governmental authorities are investigating the practice of flaring natural gas and it is possible that such states could implement additional volumetric or other restrictions on this practice which may require us to curtail or shut in production which otherwise is or would be flared due to the unavailability of acceptable delivery, transportation or processing arrangements. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

***We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.***

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our development activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fire, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

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

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

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

***Multi-well pad drilling may result in volatility in our operating results.***

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

***We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.***

In the future we may make acquisitions of assets or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and purchase prices higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. In addition, debt agreements impose certain limitations on our ability to enter into mergers or combination transactions and our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

***Some of our reserves are located near urban areas, which could increase our costs of development and delay production.***

Some of our reserves are located near urban areas, including the city of Pecos, Texas. If these urban areas expand and develop the area around our operations or the surface above our wells, or if we expand our operations closer to the urban areas, we may be exposed to additional operational and regulatory risk in that area.  In such event, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our production to market in such areas may also be more time consuming and costly than in more rural areas.  The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from the drilling of wells.

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

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. In addition, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages or cost increases could delay 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.

***We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.***

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue as commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

***Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.***

Under the EP Act of 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to approximately $1.3 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

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

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the CAA that, among other things, require PSD preconstruction and Title V operating permits for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions are also required to meet “best available control technology” standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States, which include certain of our operations. Furthermore, in June 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. However, the EPA recently indicated that it intends to reconsider certain aspects of this rule, and in June 2017 issued a proposed rulemaking that would stay the requirements of the methane rule for a period of two years. In September 2018, the EPA proposed amendments to the 2016 standards that would reduce the rule’s fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other charges. The EPA has also announced that it intends to impose methane emission standards for existing sources as well but, to date, has not yet issued a proposal. Instead, in August 2019, the EPA proposed two options for rescinding the 2016 standards. Under the EPA’s preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for volatile organic compounds (VOCs), and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements of the 2016 standards applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, 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. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. The United States became one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, which requires member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The Paris Agreement entered into force in November 2016. In June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework. In August 2017, the U.S. Department of State officially informed the United Nations of the United States’ intent to withdraw from the Paris Agreement unless it is renegotiated, and in November 2019 formally initiated the withdrawal process, which will result in an exit date of November 2020. 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. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations.

***Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.***

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing (although those standards are currently subject to revisions proposed by the Trump Administration), and advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and also finalized rules in 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands (which was challenged in a U.S. federal trial court, resulting in a decision in June 2016 against the rule, an appeal of that decision, and a U.S. federal appeals court ruling in September 2017 dismissing the appeals and vacating the trial court decision); the rule is currently the subject of a December 2017 final rulemaking by the BLM to rescind it. Shortly after the final rulemaking was issued, the state of California and several environmental groups filed lawsuits against the BLM, the Secretary of the Interior, and the Assistant Secretary for Land and Minerals Management, seeking an injunction and a declaration that the repeal violated numerous federal statutes. After the suits were filed, multiple industry groups and the state of Wyoming sought to intervene and transfer the case to federal court in Wyoming, which decided the initial legal challenge to the Obama administration's fracking regulations. A hearing was held in January 2020 to consider a motion for summary judgment in the case. However, those legal challenges are still pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The EPA report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there are above-and-below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

***Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of saltwater gathered from such activities, which could have a material adverse effect on our business.***

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition, a number of lawsuits have been filed in other states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission of Texas published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

We dispose of large volumes of saltwater gathered from our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. Furthermore, regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. It may be costly and time consuming to comply with requirements imposed by these authorities, and compliance may result in delays in the commencement or continuation of our exploration and production. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of saltwater gathered from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our 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 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 properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. 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.

***The loss of senior management or technical personnel could adversely affect operations.***

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

***Increases in interest rates could adversely affect our business.***

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. At December 31, 2019, we had $175.0 million in borrowings outstanding under our credit facility. Interest is calculated under the terms of CRP’s credit agreement based on a LIBOR spread. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

***Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.***

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

***Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.***

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

***The enactment of derivatives legislation 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 Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Title VII of the Dodd-Frank Act requires the CFTC, the SEC and the prudential regulators to promulgate rules and regulations implementing the derivatives-related provisions of the Dodd-Frank Act. While most of these regulations are already in effect, the implementation process is still ongoing, and the CFTC continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, we cannot yet predict the ultimate effect of the regulations on our business and, while most of the regulations have been adopted, any new regulations or modifications to existing regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material and adverse effect on us and our financial condition.

The CFTC has re-proposed position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. The CFTC has also finalized a related aggregation rule that requires market participants to aggregate their positions with certain other persons under common ownership and control, unless an exemption applies, for purposes of determining whether the position limits have been exceeded. If adopted, the revised position limits rule and its finalized companion rule on aggregation may have an impact on our ability to hedge exposure to price fluctuation of certain commodities. In addition to the CFTC federal position limit regime, designated contract markets ("DCMs") also have established position limit and accountability regimes. We may have to modify trading decisions or liquidate positions to avoid exceeding such limits or at the direction of the exchange to comply with accountability levels. Further, any such position limit regime, whether imposed at the federal or at the DCM level may impose added operating costs to monitor compliance with such position limit levels, addressing accountability level concerns and maintaining appropriate exemptions, if applicable.

The Dodd-Frank Act requires that certain classes of swaps be cleared on a derivatives clearing organization ("DCO") and traded on a regulated exchange, unless exempt from such clearing and trading requirements, which could result in the application of certain margin requirements imposed by DCOs and their members. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps entered into between swap dealers and certain other counterparties. We expect to qualify for and rely upon an end-user exception from the mandatory clearing and trade execution requirements for swaps entered into to hedge our commercial risks. While we also expect to qualify for and rely upon an exception from the uncleared swap margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

In addition, the European Union and other non-U.S. jurisdictions have adopted and are implementing local regulations with respect to the derivatives market which are generally comparable to the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with counterparties in foreign jurisdictions and may make transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalence across jurisdictions may increase compliance costs and make it more difficult to satisfy our regulatory obligations.

***The standardized measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated oil and natural gas reserves.***

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. As a result, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received, and the standardized measure of our estimated reserves included in this Annual Report should not be construed as accurate estimates of the current fair value of our proved reserves.

***We may not be able to keep pace with technological developments in our industry.***

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

***A security interruption or failure with respect to our information technology systems could harm our ability to effectively operate our business.***

Our ability to effectively manage and operate our business depends significantly on information technology systems. The failure of these systems to operate effectively and support our operations, challenges in transitioning to upgraded or replacement systems, difficulty in integrating new or updated systems, or a breach in security of these systems could adversely impact the operations of our business.

Any breach of our network may result in the loss of valuable business data, misappropriation of our customers' or employees' personal information, or a disruption of our business, which could harm our customer relationships and reputation, and result in lost revenues, fines or lawsuits.

Moreover, we must comply with increasingly complex and rigorous regulatory standards enacted to protect business and personal data. Any failure to comply with these regulatory standards could subject us to legal and reputational risks. Misuse of or failure to secure personal information could also result in violation of data privacy laws and regulations, proceedings against us by governmental entities or others, damage to our reputation and credibility, and could have a negative impact on revenues and profits.

***Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.***

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

***Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.***

We are subject to income taxes in the United States, and our domestic tax liabilities are subject to the allocation of expenses in differing jurisdictions. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of our deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of stock-based compensation;
- costs related to intercompany restructurings;
- changes in tax laws, regulations or interpretations thereof; or
- lower than anticipated future earnings in jurisdictions where we have lower statutory tax rates and higher than anticipated future earnings in jurisdictions where we have higher statutory tax rates.

In addition, we may be subject to audits of our income, sales and other transaction taxes by U.S. federal and state authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

**Risks Related to Our Indebtedness**

***Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on our outstanding debt.***

As of December 31, 2019, we had approximately $1.1 billion of total long-term debt and additional borrowing capacity of $624.2 million under CRP’s revolving credit facility (after giving effect to our elected commitment and $0.8 million of outstanding letters of credit). Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limit management’s discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- make it more likely that a reduction in CRP’s borrowing base following a periodic redetermination could require CRP to repay a portion of its then-outstanding bank borrowings;
- make us vulnerable to increases in interest rates as the indebtedness under CRP’s revolving credit facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to our competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for CRP to satisfy its obligations under its debt and increase the risk that we may default on its debt obligations.

***CRP may incur substantial additional indebtedness, which could further exacerbate the risks that we may face.***

Subject to the restrictions in the instruments governing CRP's outstanding indebtedness (including CRP's revolving credit facility and senior notes), CRP and its subsidiaries may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the instruments governing CRP's outstanding indebtedness do contain restrictions on the incurrence of additional indebtedness, these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial. As of December 31, 2019, CRP had additional borrowing capacity of $624.2 million under its revolving credit facility (after giving effect to our elected commitment and $0.8 million of outstanding letters of credit), all of which would be secured if borrowed.

Any increase in CRP's level of indebtedness and leverage will have several important effects on our future operations, including, without limitation:

- result in additional cash requirements to support the payment of interest on CRP's outstanding indebtedness;
- increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure; and
- depending on the levels of CRP's outstanding indebtedness, may limit our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes.

***We may not be able to generate sufficient cash to service all of CRP's indebtedness and may be forced to take other actions to satisfy CRP's obligations under applicable debt instruments, which may not be successful.***

CRP's ability to make scheduled payments on or to refinance its indebtedness depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit CRP to pay the principal, premium, if any, and interest on CRP's indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance CRP's indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require CRP to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm CRP's ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. The agreements governing CRP's indebtedness restrict CRP's ability to dispose of assets and CRP's use of the proceeds from such disposition. CRP may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit CRP to meet scheduled debt service obligations.

***Restrictions in CRP's existing and future debt agreements could limit our growth and ability to engage in certain activities.***

CRP's credit agreement and the indenture governing its senior notes contain a number of significant covenants, including restrictive covenants that may limit CRP's ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- make certain payments;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, CRP's credit agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of December 31, 2019, we were in full compliance with such financial ratios and covenants.

The restrictions in CRP's debt agreements may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive imposed on CRP.

A breach of any covenant in CRP's debt agreements would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under CRP's credit agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

***If CRP is unable to comply with the restrictions and covenants in the agreements governing its indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that CRP has borrowed.***

Any default under the agreements governing CRP's indebtedness that is not cured or waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make CRP unable to pay principal, premium, if any, and interest on such indebtedness. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on CRP's indebtedness, or if CRP otherwise fails to comply with the various covenants, including financial and operating covenants, in the agreements governing CRP's indebtedness, CRP could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under CRP's revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under CRP's revolving credit facility to avoid CRP being in default. If CRP breaches the covenants under its revolving credit facility and seeks a waiver, CRP may not be able to obtain a waiver from the required lenders. If this occurs, CRP would be in default under the revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

***Any significant reduction in the borrowing base under CRP's revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.***

CRP's revolving credit facility limits the amounts CRP can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually in the spring and fall. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the loan. The borrowing base will automatically be decreased by an amount equal to 25% of the aggregate notional amount of issued permitted senior unsecured notes. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under CRP's revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. In connection with the fall 2019 semi-annual borrowing base redetermination, the borrowing base was reaffirmed at $1.2 billion and the amount of elected commitments remained at $800.0 million.

In the future, we may not be able to access adequate funding under CRP's revolving credit facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, CRP could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service CRP's indebtedness.

***If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.***

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

**Risks Related to Our Class A Common Stock and Capital Structure**

***Our only significant asset is our current ownership of an approximate 99.6% membership interest in CRP. Distributions from CRP may not be sufficient to allow us to pay any dividends on our Class A Common Stock or satisfy our other financial obligations.***

We have no direct operations and no significant assets other than our current ownership of an approximate 99.6% membership interest in CRP. We will depend on CRP for distributions, loans and other payments to generate the funds necessary to meet our financial obligations or to pay any dividends with respect to our Class A Common Stock. Subject to certain restrictions, CRP generally will be required to (i) make pro rata distributions to its members, including us, in an amount at least sufficient to allow us to pay our taxes and (ii) reimburse us for certain corporate and other overhead expenses. However, legal and contractual restrictions in agreements governing future indebtedness of CRP, as well as the financial condition and operating requirements of CRP may limit our ability to obtain cash from CRP. The earnings from, or other available assets of, CRP may not be sufficient to pay dividends or make distributions or loans to enable us to pay any dividends on our Class A Common Stock or satisfy our other financial obligations.

***A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.***

Certain segments of the investor community have recently developed negative sentiment towards investing in the oil and gas 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. Some investors, including certain private equity companies, pension funds, university endowments and family foundations have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. Such developments could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

***If the price of our Class A Common Stock fluctuates significantly, your investment could lose value.***

Although our Class A Common Stock is listed on The NASDAQ Capital Market, we cannot assure you that an active public market will continue for our Class A Common Stock. If an active public market for our Class A Common Stock does not continue, the trading price and liquidity of our Class A Common Stock will be materially and adversely affected. If there is a thin trading market or “float” for our Class A Common Stock, the market price for our Class A Common Stock may fluctuate significantly more than the stock market as a whole. Without a large float, our Class A Common Stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our Class A 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. Furthermore, the stock market is subject to significant price and volume fluctuations, and the price of our Class A Common Stock could fluctuate widely in response to several factors, including:

Factors affecting the trading price of our Class A Common Stock may include:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;
- changes in the market’s expectations about our operating results;
- actual or anticipated impacts of oil, natural gas and NGL takeaway capacity out of the Permian Basin;
- success of competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or its markets in general;

- operating and stock price performance of other companies that investors deem comparable to us;
- our ability to market new and enhanced products on a timely basis;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of securities available for public sale;
- additions or departures of key personnel;
- sales of substantial amounts of our Class A Common Stock by our directors, executive officers or significant stockholders or the perception that such sales could occur; and
- general economic and political conditions such as recession; interest rate, fuel price, and international currency fluctuations; and acts of war or terrorism.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. For example, the closing price per share of our common stock as reported by The NASDAQ Capital Market ranged from a high of $22.75 per share in October 2018 to a low of $2.56 per share in February 2020. The changes often appear to occur without regard to specific operating performance. The price of our Class A Common Stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

***If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding our securities adversely, the price and trading volume of our securities could decline.***

The trading market for our securities will be influenced by the research and reports that industry or securities analysts may publish about us, our business, our market or our competitors. Securities and industry analysts do not currently, and may never, publish research on us. If no securities or industry analysts commence coverage of us, our stock price and trading volume would likely be negatively impacted. If any of the analysts who may cover us change their recommendation regarding our securities adversely, or provide more favorable relative recommendations about our competitors, the price of our securities would likely decline. If any analyst who may cover us were to cease coverage of us or fail to regularly publish reports on it, we could lose visibility in the financial markets, which could cause our stock price or trading volume to decline.

***Riverstone and its affiliates own a significant percentage of our outstanding voting common stock.***

Riverstone and its affiliates beneficially own approximately 28% of our voting common stock as of December 31, 2019. As long as Riverstone and its affiliates own or control a significant percentage of outstanding voting power, they may have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our board of directors, any amendment of our second amended and restated certificate of incorporation (the “Charter”) or amended and restated bylaws (the “Bylaws”), or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of Riverstone and its affiliates may not align with the interests of our other stockholders. Riverstone is in the business of making investments in companies and may acquire and hold interests in businesses that compete directly or indirectly with us. Riverstone and its affiliates may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our Charter provides that we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

***Provisions contained in our Charter and Bylaws, as well as provisions of Delaware law, could impair a takeover attempt, which may adversely affect the market price of our Class A Common Stock.***

Our Charter and Bylaws contain provisions that could have the effect of delaying or preventing changes in control or changes in our management without the consent of our board of directors. These provisions include:

- a classified board of directors, with only approximately one-third of our board of directors elected each year;
- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;

- the exclusive right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director, which prevents stockholders from being able to fill vacancies on our board of directors;
- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;
- a prohibition on stockholder action by written consent, which forces stockholder action to be taken at an annual or special meeting of our stockholders;
- the requirement that an annual meeting of stockholders may be called only by the chairman of the board of directors, the chief executive officer, or the board of directors, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;
- limiting the liability of, and providing indemnification to, our directors and officers;
- controlling the procedures for the conduct and scheduling of stockholder meetings;
- providing that directors may be removed prior to the expiration of their terms by stockholders only for cause; and
- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

These provisions, alone or together, could delay hostile takeovers and changes in control of the Company or changes in our board of directors and management.

As a Delaware corporation, we are also subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law, which prevents some stockholders holding more than 15% of our outstanding voting common stock from engaging in certain business combinations without approval of the holders of substantially all of our outstanding voting common stock. Any provision of our Charter or Bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their securities and could also affect the price that some investors are willing to pay for our securities.

***Non-U.S. holders may be subject to U.S. income tax with respect to gain on disposition of their Class A Common Stock.***

We believe that we are a United States real property holding corporation. As a result, Non-U.S. holders (defined below in the section entitled "Material U.S. Federal Income Tax Considerations") that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Class A Common Stock during a specified time period may be subject to U.S. federal income tax on a sale, exchange, or other disposition of such Class A Common Stock and may be required to file a U.S. federal income tax return. If you are a Non-U.S. holder, we urge you to consult your tax advisors regarding the tax consequences of such treatment.

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 3. LEGAL PROCEEDINGS**

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment-related disputes. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

**ITEM 4. MINE SAFETY DISCLOSURE**

Not applicable.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Class A Common Stock**

Our Class A Common Stock is currently quoted on NASDAQ under the symbol "CDEV." As of February 20, 2020, there were 13 registered holders of record of our Class A Common Stock.

**Dividend Policy**

We have not paid any cash dividends on our Class A Common Stock or Class C Common Stock to date. Our board of directors may from time to time consider whether or not to institute a dividend policy. It is our present intention to retain any earnings for use in our business operations and, accordingly, we do not anticipate the board of directors declaring any dividends in the near future.

## ITEM 6. SELECTED FINANCIAL DATA

The following data should be read in conjunction with *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Annual report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this Annual Report. Our historical results are not necessarily indicative of future operating results.

The following table shows selected historical financial information for the periods and as of the dates indicated. The term "Successor" refers to Centennial after the acquisition of the outstanding membership interests in CRP on October 11, 2016 (the "Business Combination") and the consolidation of CRP subsequent to the Business Combination. The term "Predecessor" refers to CRP for periods prior to the Business Combination.

The selected historical financial information for the periods presented may not be comparable from period to period or going forward as a result of the following transactions:

- the GMT Acquisition completed in June 2017;
- the Silverback Acquisition completed in December 2016; and
- the Business Combination completed in October 2016.

| | Successor | | | | Predecessor | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | October 11, 2016 through December 31, 2016 | January 1, 2016 through October 10, 2016[1] | Year Ended December 31,2015[1] |
| **(in thousands, except per share data)** | **2019** | **2018** | **2017** | | | |
| **Statements of Operations Data:** | | | | | | |
| Total revenues | $ 944,330 | $ 891,045 | $ 429,902 | $ 29,717 | $ 69,116 | $ 90,460 |
| Net income attributable to Class A Common Stock | 15,798 | 199,899 | 75,568 | (8,081) | (218,724) | (38,325) |
| Income (loss) per share:[2] | | | | | | |
| Basic | $ 0.06 | $ 0.76 | $ 0.32 | $ (0.05) | | |
| Diluted | $ 0.06 | $ 0.75 | $ 0.32 | $ (0.05) | | |
| **Cash Flows Data:** | | | | | | |
| Net cash provided by operating activities | $ 564,173 | $ 670,011 | $ 259,918 | $ 9,410 | $ 51,740 | $ 68,882 |
| Net cash used in investing activities | (932,989) | (1,068,664) | (992,306) | (1,749,733) | (101,434) | (198,635) |
| Net cash provided by financing activities | 362,937 | 294,160 | 724,220 | 1,874,268 | 47,926 | 118,504 |

| | Successor | | | | Predecessor |
|---|---|---|---|---|---|
| | December 31, | | | | December 31, 2015[1] |
| **(in thousands)** | **2019** | **2018** | **2017** | **2016** | |
| **Balance Sheet Data:** | | | | | |
| Total assets | $ 4,688,288 | $ 4,260,021 | $ 3,616,569 | $ 2,651,642 | $ 616,295 |
| Long-term debt, net | 1,057,389 | 691,630 | 390,764 | — | 138,649 |
| Total equity | 3,270,701 | 3,243,869 | 3,003,972 | 2,552,935 | 450,864 |

(1) The selected historical consolidated financial information of CRP as of and for the year ended December 31, 2015 and for the period from January 1, 2016 through October 10, 2016 was derived from the audited historical consolidated financial statements of CRP.

(2) No cash or stock dividends were declared or paid on our Class A Common Stock during the periods presented.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" in this Annual Report. The following discussion and analysis may contain forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, future market prices for oil, natural gas and NGLs, future production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed in "Cautionary Statement Concerning Forward-Looking Statements" and "Item 1A. Risk Factors" in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.*

### Overview

We are an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are primarily in the Delaware Basin, a sub-basin of the Permian Basin. Our capital programs are specifically focused on projects that we believe provide the highest return on capital.

### Market Conditions

The oil and natural gas industry is cyclical and commodity prices can be volatile. It is likely that commodity prices will continue to fluctuate due to global supply and demand, inventory levels, weather conditions, geopolitical events and other factors. For example, WTI spot prices for crude oil declined significantly to a low of $42.53 per barrel in the second quarter of 2017 but reached a high of $76.41 per barrel in the fourth quarter of 2018, while the average quarterly crude oil price remained below $60 per barrel during the entirety of 2019.

The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2017:

| | 2017 | | | | 2018 | | | | 2019 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| Crude Oil (per Bbl) | $ 51.82 | $ 48.32 | $ 48.17 | $ 55.31 | $ 62.91 | $ 68.07 | $ 69.50 | $ 58.81 | $ 54.90 | $ 59.81 | $ 56.45 | $ 56.94 |
| Natural Gas (per MMBtu) | $ 3.06 | $ 3.14 | $ 2.95 | $ 2.91 | $ 3.08 | $ 2.85 | $ 2.93 | $ 3.77 | $ 2.88 | $ 2.51 | $ 2.33 | $ 2.34 |

A sustained drop in oil, natural gas and NGL prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil, natural gas and NGLs that we can produce economically and therefore potentially lower our oil, natural gas and NGL reserve quantities.

Lower commodity prices (including our realized differentials) in the future could result in impairments of our proved oil and natural gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower realized prices may also reduce the borrowing base under CRP's credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if any borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under the credit agreement.

### 2019 Highlights and Future Considerations

#### *Operational Highlights*

During 2019, we grew our production and oil and natural gas reserves by developing our acreage with an increased focus on optimizing drilling and completion results, drilling extended laterals and managing costs. During 2019, we operated a six-rig drilling program through mid-September and a five-rig program thereafter, which enabled us to complete and bring online 84 gross operated wells during the year with an average effective lateral length of approximately 7,700 feet. In comparison, we operated, on average, a seven-rig drilling program during 2018 and completed 80 gross operated wells with an average effective lateral length of approximately 7,400 feet.

***Financing Highlights***

In connection with our credit facility's spring 2019 semi-annual borrowing base redetermination, the borrowing base was increased from $1.0 billion to $1.2 billion, but the amount of elected commitments remained at $800.0 million. In addition, CRP and the lenders amended the credit agreement to reduce the applicable margin for LIBOR loans by 25 basis points to a range of 125 to 225 basis points and to reduce the applicable margin by 25 basis points for base rate loans to a range of 25 to 125 basis points, in each case depending on the percentage of the borrowing base utilized. These reductions in the applicable margins became effective in April 2019 and remain applicable as long as CRP's total leverage ratio is less than or equal to 3.0 to 1.0; otherwise, the original applicable margins would be applied.

In connection with our credit facility's fall 2019 semi-annual borrowing base redetermination, the borrowing base was reaffirmed at $1.2 billion, and the amount of elected commitments remained at $800.0 million.

## Results of Operations

***For the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018***

The following table provides the components of our net revenues and net production (net of all royalties, overriding royalties and production due to others) for the periods indicated, as well as each period's average prices and average daily production volumes:

| | Year Ended December 31, | | Increase/(Decrease) | |
|---|---|---|---|---|
| | 2019 | 2018 | $ | % |
| **Net revenues (in thousands):** | | | | |
| Oil sales | $ 810,655 | $ 709,813 | $ 100,842 | 14 % |
| Natural gas sales | 44,556 | 62,325 | (17,769) | (29)% |
| NGL sales | 89,119 | 118,907 | (29,788) | (25)% |
| Oil and gas sales | $ 944,330 | $ 891,045 | $ 53,285 | 6 % |
| | | | | |
| **Average sales price:** | | | | |
| Oil (per Bbl) | $ 52.02 | $ 55.98 | $ (3.96) | (7)% |
| Effect of derivative settlements on average price (per Bbl) | (1.13) | 1.48 | (2.61) | (176)% |
| Oil net of hedging (per Bbl) | $ 50.89 | $ 57.46 | $ (6.57) | (11)% |
| | | | | |
| Average NYMEX price for oil (per Bbl) | $ 57.03 | $ 64.76 | $ (7.73) | (12)% |
| Oil differential from NYMEX | (5.01) | (8.78) | 3.77 | 43 % |
| | | | | |
| Natural gas (per Mcf) | $ 1.07 | $ 1.97 | $ (0.90) | (46)% |
| Effect of derivative settlements on average price (per Mcf) | 0.29 | 0.06 | 0.23 | 383 % |
| Natural gas net of hedging (per Mcf) | $ 1.36 | $ 2.03 | $ (0.67) | (33)% |
| | | | | |
| Average NYMEX price for natural gas (per Mcf) | $ 2.52 | $ 3.15 | $ (0.63) | (20)% |
| Natural gas differential from NYMEX | (1.45) | (1.18) | (0.27) | (23)% |
| | | | | |
| NGL (per Bbl) | $ 17.03 | $ 27.45 | $ (10.42) | (38)% |
| | | | | |
| **Net production:** | | | | |
| Oil (MBbls) | 15,582 | 12,679 | 2,903 | 23 % |
| Natural gas (MMcf) | 41,703 | 31,707 | 9,996 | 32 % |
| NGL (MBbls) | 5,234 | 4,332 | 902 | 21 % |
| Total (MBoe)[1] | 27,766 | 22,295 | 5,471 | 25 % |
| | | | | |
| **Average daily net production:** | | | | |
| Oil (Bbls/d) | 42,692 | 34,737 | 7,955 | 23 % |
| Natural gas (Mcf/d) | 114,254 | 86,868 | 27,386 | 32 % |
| NGL (Bbls/d) | 14,338 | 11,868 | 2,470 | 21 % |
| Total (Boe/d)[1] | 76,072 | 61,082 | 14,990 | 25 % |

(1) Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

*Oil, Natural Gas and NGL Sales Revenues*. Total net revenues for the year ended December 31, 2019 were $53.3 million (or 6%) higher than total net revenues for the year ended December 31, 2018. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Net production volumes for oil, natural gas, and NGLs increased 23%, 32% and 21%, respectively, between periods. The oil volume increase between periods resulted primarily from drilling success in the Delaware Basin. During the year ended December 31, 2019, 84 gross operated wells were placed on production in the Delaware Basin, which added 5,611 MBbls of net oil production during the year. These oil volume increases were partially offset by normal production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, typically resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. As a result, our crude oil production increased 23% and NGL production increased 21% when comparing the year ended December 31, 2019 to 2018. However, we produced a higher percentage (32%) of gas volumes (relative to crude oil and NGLs) in 2019 compared to 2018, due to a decrease during

2019 in the ratio of new production from wells added during the year compared to base production from pre-existing wells, combined with the fact that older wells generally have higher gas yields over time than newly drilled wells do.

The increases in production volumes between periods were partially offset by lower average realized sales prices for oil, natural gas and NGLs for the year ended December 31, 2019 compared to 2018. The average price for oil before the effects of hedging decreased 7%, the average price for natural gas before the effects of hedging decreased 46% and the average price for NGLs decreased 38% between periods. The 7% decrease in the average realized oil price was the result of lower NYMEX crude prices between periods (average NYMEX oil prices decreased 12%) partially offset by improved oil differentials (a decrease of $3.77 per Bbl) during 2019. The average realized sales price of natural gas between periods decreased 46% due to lower average NYMEX gas prices between periods (average NYMEX prices decreased 20%) and wider gas differentials (an increase of $0.27 per Mcf). The continued widening of natural gas differentials was due to natural gas pipeline takeaway capacity constraints impacting the Permian Basin, which has in turn depressed natural gas prices in West Texas and New Mexico. A new gas pipeline was placed into service late in the third quarter of 2019 in the Permian Basin, and continued construction of additional natural gas pipelines are planned through 2022. These third party pipelines are expected to provide relief from these wider natural gas differentials once they come online. The overall 38% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products in 2019.

*Operating Expenses.* The following table sets forth selected operating expense data for the periods indicated:

| | Year Ended December 31, | | Increase/(Decrease) | |
|---|---|---|---|---|
| | 2019 | 2018 | $ | % |
| **Operating costs (in thousands):** | | | | |
| Lease operating expenses | $ 145,976 | $ 83,313 | $ 62,663 | 75 % |
| Severance and ad valorem taxes | 63,200 | 56,523 | 6,677 | 12 % |
| Gathering, processing, and transportation expense | 72,834 | 57,624 | 15,210 | 26 % |
| **Operating costs per Boe:** | | | | |
| Lease operating expenses | $ 5.26 | $ 3.74 | $ 1.52 | 41 % |
| Severance and ad valorem taxes | 2.28 | 2.54 | (0.26) | (10)% |
| Gathering, processing, and transportation expense | 2.62 | 2.58 | 0.04 | 2 % |

*Lease Operating Expenses.* Lease operating expenses ("LOE") for the year ended December 31, 2019 increased $62.7 million compared to the year ended December 31, 2018. Higher LOE for 2019 was primarily related to a $43.3 million increase in expense associated with higher well count. We had 349 gross operated horizontal wells as of December 31, 2019 compared to 263 gross operated horizontal wells as of December 31, 2018. The net increase in well count was mainly the result of our successful drilling activity adding 84 gross operated wells in 2019, which was further adjusted for acquisitions and divestitures. In addition, workover expense increased $19.4 million between periods as result of our higher well count and related higher workover activity.

LOE on a per Boe basis increased when comparing the year ended December 31, 2019 to the year ended December 31, 2018. LOE per Boe was $5.26 for the year ended December 31, 2019, which represents an increase of $1.52 per Boe from 2018. This increase in rate was mainly due to our higher level of workover activity discussed above which added $0.58 to our LOE rate in 2019, as well as (i) a decline in the ratio of flush production to base production based on our level of drilling and completion ("D&C") activity in 2019; (ii) higher monthly rental rates for electric submersible pumps ("ESPs") and wellhead generators, (iii) increased wellhead chemical costs, and (iv) an increased number of field employees, resulting in higher labor costs.

*Severance and Ad Valorem Taxes.* Severance and ad valorem taxes for the year ended December 31, 2019 increased $6.7 million compared to the year ended December 31, 2018. Severance taxes are primarily based on the market value of our production at the wellhead, while ad valorem taxes are generally based on the taxable value of proved developed oil and natural gas properties and vary across the different counties in which we operate. Severance and ad valorem taxes as a percentage of total net revenues increased to 6.7% for the year ended December 31, 2019 as compared to 6.3% for the year ended December 31, 2018 due to increased ad valorem taxes of $5.9 million between periods as a result of our higher well count and higher oil and gas property values.

Severance and ad valorem taxes decreased on a per Boe basis to $2.28 for the year ended December 31, 2019 from $2.54 for the year ended December 31, 2018. This 10% decrease in rate is due to lower average realized sales prices for oil, natural gas and NGLs between periods.

*Gathering, Processing and Transportation Expenses.* Gathering, processing and transportation costs ("GP&T") for the year ended December 31, 2019 increased $15.2 million compared to the year ended December 31, 2018 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing costs, transportation tariffs and gathering fees being incurred.

On a per Boe basis, GP&T increased 2% from $2.58 for the year ended December 31, 2018 to $2.62 per Boe for the year ended December 31, 2019. However, these fees are mainly incurred on our volumes of natural gas and NGLs processed, and the per Boe rate on a natural gas and NGL volume basis (i.e. excluding crude oil barrels) was $5.98 for the year ended December 31, 2019, which was consistent with our rate of $5.99 for the comparable 2018 period.

*Depreciation, Depletion, and Amortization.* The following table summarizes our depreciation, depletion and amortization ("DD&A") for the periods indicated:

| | Year Ended December 31, | |
|---|---|---|
| **(in thousands, except per Boe data)** | **2019** | **2018** |
| Depreciation, depletion and amortization | $ 444,243 | $ 326,462 |
| Depreciation, depletion and amortization per Boe | $ 16.00 | $ 14.64 |

Our DD&A rate can fluctuate as a result of finding and development costs incurred, acquisitions, impairments, as well as changes in proved reserves or proved developed reserves. For the year ended December 31, 2019, DD&A expense amounted to $444.2 million, an increase of $117.8 million over 2018. The primary factor contributing to higher DD&A expense in 2019 was the increase in our overall production volumes between periods, which added $80.3 million of incremental DD&A for the year ended December 31, 2019, while higher DD&A rates between periods contributed an additional $37.5 million of DD&A expense in 2019.

DD&A per Boe was $16.00 for the year ended December 31, 2019 compared to $14.64 in 2018. The primary factor contributing to this higher DD&A rate was continued infrastructure and other capital spend (having no associated proved reserves adds) that were placed into service during 2019.

*Impairment and Abandonment Expense.* For the year ended December 31, 2019, $47.2 million of impairment and abandonment expense was incurred related to undeveloped leasehold acreage. This expense consisted of the following: (i) $19.1 million related to non-core acreage that expired during 2019 after efforts to extend, sell or trade these leases were unsuccessful, (ii) $16.6 million for impaired acreage following an acreage sale initiated in the first quarter of 2019, and (iii) $11.5 million related to the amortization of leasehold expiration costs associated with individually insignificant unproved properties.

For the year ended December 31, 2018, $11.1 million of abandonment expense was incurred related to undeveloped leasehold acreage that expired during the period after efforts to extend, sell or trade these leases were unsuccessful.

*Exploration Expense.* The following table summarizes exploration expense for the periods indicated:

| | Year Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2019** | **2018** |
| Geological and geophysical costs | $ 8,708 | $ 7,624 |
| Stock-based compensation expense | 2,682 | 1,816 |
| Exploratory dry hole costs | — | 528 |
| Exploration expense | $ 11,390 | $ 9,968 |

Exploration expense was $11.4 million for the year ended December 31, 2019 compared to $10.0 million for the year ended December 31, 2018. Exploration expense mainly consists of topographical studies, geographical and geophysical ("G&G") projects, and salaries and expenses of G&G personnel. The period over period increase was primarily related to an increase in G&G personnel expenses of $2.7 million during 2019 due to the average number of geologists increasing between periods. This increase was partially offset by lower costs incurred on G&G projects and seismic studies between periods and no exploratory dry hole costs incurred during 2019.

*General and Administrative Expenses.* The following table summarizes our general and administrative ("G&A") expenses for the periods indicated:

| | Year Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2019** | **2018** |
| Cash general and administrative expenses | $ 52,841 | $ 44,450 |
| Stock-based compensation | 26,315 | 18,854 |
| General and administrative expenses | $ 79,156 | $ 63,304 |

G&A expenses for the year ended December 31, 2019 were $79.2 million compared to $63.3 million for the year ended December 31, 2018. G&A expenses were higher in 2019 primarily due to $5.0 million in increased employee salaries and payroll costs, $7.5 million in higher stock-based compensation and $1.8 million in increased software costs and office rental expenses compared to the prior year period. These costs were higher for the year ended December 31, 2019 due to our increase in headcount during the year. In addition, we incurred a $1.8 million non-recurring charge for the settlement of a water disposal contract dispute in 2019.

*Other Income and Expense.*

*Interest Expense.* The following table summarizes interest expense for the periods indicated:

| | Year Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2019** | **2018** |
| Credit facility | $ 8,371 | $ 5,975 |
| 5.375% Senior Notes due 2026 | 21,500 | 21,500 |
| 6.875% Senior Notes due 2027 | 27,309 | — |
| Amortization of debt issuance costs and debt discount | 2,861 | 1,749 |
| Interest capitalized | (4,050) | (2,866) |
| Total | $ 55,991 | $ 26,358 |

Interest expense was $29.6 million higher for the year ended December 31, 2019 compared to the year ended December 31, 2018 primarily due to $27.3 million in interest we incurred in 2019 related to our 2027 Senior Notes that were issued in March of that year, as well as increased borrowings under our credit facility in 2019. Our weighted average borrowings outstanding under our credit facility were $154.8 million during 2019 compared to $98.2 million in 2018. Our credit facility's weighted average effective interest rate was 3.7% for 2019 as compared to 3.8% during 2018.

*Net Gain (Loss) on Derivative Instruments.* Net gains and losses are a function of i) fluctuations in mark-to-market derivative fair values associated with corresponding changes in the forward price curve for the underlying commodities and ii) monthly cash settlements of hedged derivative positions.

The following table presents gains and losses on our derivative instruments for the periods indicated:

| | Year Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2019** | **2018** |
| Cash settlement gains (losses) | $ (5,655) | $ 20,610 |
| Non-cash mark-to-market derivative gain (loss) | 4,094 | (5,274) |
| Total | $ (1,561) | $ 15,336 |

*Income Tax Expense*. During the year ended December 31, 2019 and 2018, we recognized income tax expense amounting to $5.8 million and $59.4 million, or 26% and 22% of pre-tax income, respectively. The decrease in income tax expense for the year ended December 31, 2019 as compared to 2018 was primarily due to the decrease in pre-tax income of $250.0 million between periods. However, the increase in the effective tax rate was due to $3.6 million in net permanent items recognized in the current period mainly related to certain amounts of nondeductible equity based compensation.

***For the Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017***

Refer to *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* in the 2018 Annual Report on Form 10-K filed with the SEC for a discussion of the results of operations for the year ended December 31, 2018 compared to the year ended December 31, 2017.

## Liquidity and Capital Resources

### *Overview*

Our drilling and completion and land acquisition activities require us to make significant capital expenditures. Historically, our primary sources of liquidity have been cash flows from operations, borrowings under CRP's revolving credit facility, and proceeds from offerings of debt or equity securities. To date, our primary use of capital has been for drilling and development capital expenditures and for the acquisition of land and oil and natural gas properties.

The following table summarizes our capital expenditures ("capex") incurred during the year:

| (in millions) | Year Ended December 31, 2019 |
|---|---|
| Drilling and completion capital expenditures | $ 691.4 |
| Facilities, infrastructure and other | 162.0 |
| Land | 38.4 |
| Total capital expenditures | $ 891.8 |

We continually evaluate our capital needs and compare them to our capital resources. Our estimated capital expenditure budget for 2020 is $590 million to $690 million, of which $490 million to $550 million is allocated to D&C activity. We expect to fund our capex budget primarily with cash flows from operations and any remaining unfunded portion with either borrowings under our credit agreement or with proceeds received from the contemplated divestiture of our saltwater disposal assets.

Because we are the operator of a high percentage of our acreage, we can control the amount and timing of these capital expenditures. We could choose to defer or accelerate a portion of our planned capex depending on a variety of factors, including, but not limited to: the success of our drilling activities; prevailing and anticipated prices for oil and natural gas; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; seasonal conditions; drilling and acquisition costs; and the level of participation by other working interest owners.

Based upon current oil and natural gas price expectations for 2020, we believe that our cash flows from operations and borrowings under our credit facility or otherwise will provide us with sufficient liquidity to execute our current capex budget. However, our future cash flows are subject to a number of variables, including the future level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot ensure that other needed capital will be available on acceptable terms or at all. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional sources for funding capital investments. As we pursue our future development program, we are actively assessing the correct mix of reserve-based borrowings and debt offerings. If we require additional capital to fund acquisitions, we may also seek such capital through traditional reserve-based borrowings, offerings of debt and equity securities, asset sales or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

### *Analysis of Cash Flow Changes*

The following table summarizes our cash flows for the periods indicated:

| (in thousands) | Year Ended December 31, 2019 | 2018 | 2017 |
|---|---|---|---|
| Net cash provided by operating activities | $ 564,173 | $ 670,011 | $ 259,918 |
| Net cash used in investing activities | (932,989) | (1,068,664) | (992,306) |
| Net cash provided by financing activities | 362,937 | 294,160 | 724,220 |

*Cash Flows from 2019 Compared to 2018.* For the year ended December 31, 2019, we generated $564.2 million of cash from operating activities, a decrease of $105.8 million from 2018. Cash provided by operating activities decreased primarily due to lower realized prices for crude oil, natural gas and NGLs, higher lease operating expenses, severance and ad valorem taxes, GP&T costs, exploration expense, cash general and administrative expenses, interest payments, cash settlement losses from derivatives and the timing of our supplier payments during 2019. These declining factors were partially offset by higher crude oil, natural gas and NGL production volumes and the timing of our receivable collections during 2019 as compared to the 2018 period. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on fluctuations in our operating expenses between periods.

For the year ended December 31, 2019, cash flows from operating activities, cash on hand, proceeds from sales of oil and gas properties and proceeds from the issuance of our 2027 Senior Notes were used to repay net borrowings of $125.0 million under our credit facility, to finance $855.2 million of drilling and development capex, to fund $103.7 million in oil and gas property acquisitions and to purchase $8.9 million of other property and equipment.

*Cash Flows from 2018 Compared to 2017*. For the year ended December 31, 2018, we generated $670.0 million of cash from operating activities, an increase of $410.1 million from 2017. Cash provided by operating activities increased primarily due to higher crude oil, natural gas and NGL production volumes, higher realized sales prices for crude oil and NGLs, higher cash derivative settlement gains, lower exploration expense and the timing of our receivable collections and supplier payments during 2018. These positive factors were partially offset by lower realized prices for natural gas, higher lease operating expenses, severance and ad valorem taxes, GP&T costs, general and administrative expenses and interest payments for the year ended December 31, 2018 as compared to 2017.

For the year ended December 31, 2018, cash flows from operating activities, cash on hand, proceeds from sales of oil and natural gas properties, and $300.0 million in net borrowings under our credit facility were used to finance $998.2 million of drilling and development expenditures and $212.5 million in oil and gas property acquisitions.

In 2017, cash from operating activities, cash on hand and $390.8 million in net proceeds from the issuance of our 2026 Senior Notes were used to finance $574.3 million for drilling and development capital expenditures and repay net borrowings under our credit facility. Net proceeds of $333.5 million from the issuance of Class A Common Stock together with cash on hand, $35.0 million in net borrowings under the credit facility and proceeds from the sale of oil and gas properties were used to finance $435.5 million in oil and gas property acquisitions including the GMT Acquisition and the remainder of the Silverback Acquisition.

***Credit Agreement***

On May 4, 2018, CRP entered into an amended and restated credit agreement with a syndicate of banks that as of December 31, 2019, had a borrowing base of $1.2 billion and elected commitments of $800.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of December 31, 2019, we had $175.0 million in borrowings outstanding and $624.2 million in available borrowing capacity, which was net of $0.8 million in letters of credit outstanding. In connection with the credit facility's fall 2019 semi-annual borrowing base redetermination, the borrowing base was reaffirmed at $1.2 billion and the amount of elected commitments remained at $800.0 million.

CRP's credit agreement contains restrictive covenants that limit its ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make or declare dividends; (v) enter into commodity hedges exceeding a specified percentage of CRP's expected production; (vi) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (vii) incur liens; (viii) sell assets; and (ix) engage in transactions with affiliates.

CRP's credit agreement also requires it to maintain compliance with the following financial ratios: (i) a current ratio, which is the ratio of CRP's consolidated current assets (including unused commitments under its revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the credit agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter periods ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with these covenants and the financial ratios described above as of December 31, 2019 and through the filing of this Annual Report.

For further information on our credit agreement, refer to *Note 4—Long-Term Debt*, Item 8 of this Annual Report.

***Senior Notes***

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (the "2026 Senior Notes") and on March 15, 2019, CRP issued $500.0 million of 6.875% senior notes due 2027 (the "2027 Senior Notes" and collectively with the 2026 Senior Notes the "Senior Notes") in 144A private placements. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of CRP's current subsidiaries that guarantee CRP's revolving credit facility. The Senior Notes are not guaranteed by Centennial, nor are we subject to the terms of the indentures governing the Senior Notes.

The indentures governing the Senior Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP's ability and the ability of CRP's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of December 31, 2019 and through the filing of this Annual Report.

For further information on our Senior Notes, refer to *Note 4—Long-Term Debt* , Item 8. Financial Statements and Supplementary Data in this Annual Report.

### *Off-Balance Sheet Arrangements*

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2019, we had no off-balance sheet arrangements.

### *Contractual Obligations*

We routinely enter into or extend operating and transportation agreements, office and equipment leases, drilling rig contracts, among others, in the ordinary course of business. The following table summarizes our obligations and commitments as of December 31, 2019 to make future payments under long-term contracts for the time periods specified below.

| **(in thousands)** | **2020** | **2021** | **2022** | **2023** | **2024** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Operating Leases [(1)] | $ 9,573 | $ 3,033 | $ 425 | $ — | $ — | $ — | $ 13,031 |
| Water disposal agreements [(2)] | 2,237 | 100 | — | — | — | — | 2,337 |
| Purchase obligations [(3)] | 9,302 | 3,360 | — | — | — | — | 12,662 |
| Asset retirement obligations [(4)] | 581 | — | — | — | 664 | 15,629 | 16,874 |
| Long term debt obligations [(5)] | — | — | — | 175,000 | — | 900,000 | 1,075,000 |
| Cash interest expense on long-term debt obligations [(6)] | 63,413 | 63,413 | 63,413 | 60,576 | 55,875 | 100,637 | 407,327 |
| Transportation agreements [(7)] | 13,393 | 9,061 | 1,773 | — | — | — | 24,227 |
| Total | $ 98,499 | $ 78,967 | $ 65,611 | $ 235,576 | $ 56,539 | $ 1,016,266 | $ 1,551,458 |

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(1) Operating leases include our drilling rig contracts, office rental agreements, and other wellhead equipment. Please refer to *Note 15—Leases*, Item 8. Financial Statements and Supplementary Data in this Annual Report for details on our operating lease commitments.

(2) Water disposal agreements consist of contracts for transportation and disposal of produced water from our operated wells. Under the terms of these agreements, we are obligated to provide a minimum volume of produced water or else pay for any deficiencies at the prices stipulated in the contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts as of December 31, 2019. Actual expenditures under these contracts may exceed the minimum commitments presented above.

(3) Purchase obligations include purchase agreements to buy frac sand, which is used in our well fracture stimulation process. Under the terms of these agreements, we are obligated to purchase a minimum volume of frac sand at a fixed sales price. The obligations reported above represent our minimum financial commitments pursuant to the terms of the contracts as of December 31, 2019. Actual expenditures under these contracts may exceed the minimum commitments presented above.

(4) Asset retirement obligations reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and gas wells and the related land restoration in accordance with applicable laws and regulations.

(5) Long-term debt consists of the principal amounts of the Senior Notes and borrowings outstanding under our credit agreement maturing on May 4, 2023.

(6) Cash interest expense on the Senior Notes is estimated assuming no principal repayment until the maturity of the instruments. Cash interest expense on the credit agreement includes unused commitment fees and assumes no additional principal borrowings, repayments or changes to commitments under the agreement through the instrument due date.

(7) Transportation agreements include various firm natural gas transportation contracts whereby we are required to deliver a minimum volume of natural gas or else pay for any deficiencies at prices stipulated in the contracts. The obligations reported above represent minimum financial commitments pursuant to the terms of these contracts. However, our expenditures under these contracts may exceed the minimum commitments presented above.

## Recently Issued Accounting Standards

Please refer to *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, Item 8. Financial Statements and Supplementary Data in this Annual Report for a discussion of recently issued accounting standards and their anticipated effect on our business.

## 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 GAAP. The preparation of these statements requires us to make certain assumptions, judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as, the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, commodity prices, production performance, drilling results, mechanical problems, general business conditions, our assumptions and other factors. A summary of our significant accounting policies is detailed in *Note 1—Basis of Presentation and Summary of Significant Accounting Policies*, Item 8. Financial Statements and Supplementary Data in this Annual Report.

We have outlined certain of our accounting policies below which require the application of significant judgment by our management.

### *Oil and Natural Gas Reserve Quantities*

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil, natural gas and NGL reserves. Reserve quantities and the related estimates of future net cash flows are used as inputs in our calculation of depletion, evaluation of proved properties for impairment, assessment of expected realizability of our deferred income tax assets and calculation of the standardized measure of discounted future net cash flows.

The process of estimating quantities of proved reserves is inherently imprecise and relies on the following: i) interpretations and judgment of available geological, geophysical, engineering and production data; ii) certain economic assumptions, some of which are mandated by the SEC, such as commodity prices; and iii) assumptions and estimates of underlying inputs such as operating expenses, capital expenditures, plug and abandonment costs and taxes. All of these assumptions may differ substantially from actual results, which could result in a significant change in the estimated reserves and future net cash flows. For example, if the crude oil and natural gas prices used in our year-end reserve estimates were to increase or decrease by 10%, our proved reserve quantities at December 31, 2019 would increase by 4.4 MMBoe (1%) or decrease by 22.3 MMBoe (7%), respectively, and the pre-tax PV10% of our proved reserves would increase by $509.4 million (23%) or decrease by $503.1 million (23%), respectively. We continually make revisions to reserve estimates throughout the year as additional information becomes available and we make changes to depletion rates in the same period that changes to reserve estimates are made.

### *Impairment of Oil and Natural Gas Properties*

We assess our proved properties for impairment when events or changes in circumstances indicate that the carrying value of assets may not be recoverable. For purposes of an impairment evaluation, our proved oil and natural gas properties must be grouped at the lowest level for which independent cash flows can be identified. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. Fair value calculated for the purpose of testing impairment is estimated using the present value of expected future cash flows method. Fair value estimates are based on projected financial information which we believe to be reasonably likely to occur. However, such future cash flow estimates are based on numerous assumptions that can materially affect our estimates, and such assumptions are subject to change with variations in commodity prices, production performance, drilling results, underlying oil and gas reserves, and other external factors.

Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves. Unproved properties with individually significant acquisition costs are periodically assessed for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or changes in future plans to develop acreage. Unproved properties which are not individually significant are amortized by prospect, based on our historical experience, current drilling plan, existing geological data and average lease terms. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment charges.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The term “market risk” as it applies to our business refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates, and we are exposed to market risk as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

***Commodity Price Risk***

Our primary market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. Based on our production for the year ended December 31, 2019, our oil and gas sales for the year ended December 31, 2019 would have moved up or down $81.0 million for each 10% change in our average realized oil price per Bbl, $8.9 million for each 10% change in our average realized NGL price per Bbl, and $4.5 million for each 10% change in our average realized natural gas price per Mcf.

Due to this volatility, we have historically used, and we may elect to continue to selectively use, commodity derivative instruments (such as collars, swaps and basis swaps) to mitigate price risk associated with a portion of our anticipated production. Our derivative instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in oil and natural gas prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil and natural gas prices, but alternatively they may partially limit our potential gains from future price increases. Our credit agreement limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production from proved properties.

The following table summarizes the terms of the swap contracts we had in place as of December 31, 2019 and additional contracts entered into through February 20, 2020. Refer to *Note 7—Derivative Instruments*, Item 8. Financial Statements and Supplementary Data in this Annual Report for open derivative positions as of December 31, 2019:

| | Period | Volume (Bbl) | Volume (Bbls/d) | Weighted Average Differential ($/Bbl)[1] |
|---|---|---|---|---|
| Crude oil basis swaps | January 2020 - March 2020 | 273,000 | 3,000 | $ 0.67 |
| | April 2020 - June 2020 | 273,000 | 3,000 | 0.67 |
| | July 2020 - September 2020 | 276,000 | 3,000 | 0.67 |
| | October 2020 - December 2020 | 276,000 | 3,000 | 0.67 |

[1] These oil basis swap transactions are settled based on the difference between the arithmetic average of the ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices, during each applicable settlement period.

| | Period | Volume (MMBtu) | Volume (MMBtu/d) | Weighted Average Fixed Price ($/MMBtu)[1] |
|---|---|---|---|---|
| Natural gas swaps - Henry Hub | April 2020 - October 2020 | 6,420,000 | 30,000 | $ 2.03 |

[1] These natural gas swap contracts are settled based on NYMEX Henry Hub price as of the specified settlement date.

Changes in the fair value of derivative contracts from December 31, 2018 to December 31, 2019, are presented below:

| (in thousands) | Commodity derivative asset (liability) |
|---|---|
| Net fair value liability of oil and gas derivative contracts outstanding as of December 31, 2018 | $ (4,419) |
| Contracts settled | 5,655 |
| Change in the futures curve of forecasted commodity prices[1] | (1,561) |
| Net fair value liability of oil and gas derivative contracts outstanding as of December 31, 2019 | $ (325) |

[1] At inception, new derivative contracts entered into by us have no intrinsic value.

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2019 would cause a $0.1 million increase or decrease, respectively, in this fair value liability.

***Interest Rate Risk***

Our ability to borrow and the rates offered by lenders can be adversely affected by deteriorations in the credit markets and/or downgrades in our credit rating. CRP's credit facility interest rate is based on a LIBOR spread, which exposes us to interest rate risk if we have borrowings outstanding.

At December 31, 2019, we had $175.0 million of debt outstanding under our credit agreement, with a weighted average interest rate of 3.0%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would be approximately $1.8 million per year. We do not currently have or intend to enter into any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

The remaining long-term debt balance of $882.4 million consists of our Senior Notes, which have fixed interest rates; therefore, this balance is not affected by interest rate movements. For additional information regarding our debt instruments, see *Note 4—Long-Term Debt*, in Item 8. Financial Statements and Supplementary Data in this Annual Report.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### CENTENNIAL RESOURCE DEVELOPMENT, INC.
### INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

## Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Centennial Resource Development, Inc.:

*Opinion on the Consolidated Financial Statements*

We have audited the accompanying consolidated balance sheets of Centennial Resource Development, Inc. and subsidiaries (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have 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 24, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*Change in Accounting Principle*

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Update 2016-02 Leases (ASC Topic 842).

*Basis for Opinion*

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

*Critical Audit Matter*

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

*Assessment of the impact of estimated oil and gas reserves on depletion expense related to proved oil and gas properties*

As discussed in Note 1 to the consolidated financial statements, capitalized proved property acquisition and development costs are depleted on a units-of-production method, which is based on the estimated oil and gas reserves remaining. For the year ended December 31, 2019, the Company recorded depletion expense of proved oil and gas properties included in total depreciation, depletion, and amortization expense of $444.2 million. The estimation of economically recoverable proved oil and gas reserves requires the expertise of professional petroleum reserve engineers who take into consideration forecasted production, operating and development cost assumptions and forecasted oil and gas prices inclusive of market differentials. The Company annually engages independent reserve engineers to estimate the proved oil and gas reserves and the Company’s internal reserve engineers quarterly update the estimates of proved oil and gas reserves.

We identified the assessment of the impact of estimated oil and gas reserves on depletion expense related to proved oil and gas reserves as a critical audit matter. There was a high degree of subjectivity in evaluating the estimate of proved oil and gas reserves, which is a significant input into the calculation of depletion as auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production, operating costs, and forecasted oil and gas prices inclusive of market differentials.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company’s process to estimate proved oil and gas reserves, including controls related to the assumptions used in the proved oil and gas reserves estimate, and to calculate depletion expense. We assessed the competence, capabilities, and objectivity of the Company’s internal reserve engineers and the independent reserve engineers engaged by the Company. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We assessed the data used in the average of the first-day-of-the-month pricing assumptions used in the internal reserve engineers’ and the independent reserve engineers’ estimates of the proved reserves to publicly available oil and gas benchmark pricing data, calculations of historical differentials and existing contractual arrangements. We evaluated assumptions used in the internal reserve engineers’ and independent reserve engineers’ estimates regarding future operating and development costs based on historical information including assessing the nature and timing of future development costs compared to development plan. Additionally, we compared the forecasted production volumes to historical production, and we compared the Company’s historical production forecasts to actual production volumes to assess the Company’s ability to accurately forecast. We read the findings of the Company’s independent reserve engineers in order to understand the methods and assumptions used by the specialists in connection with our evaluation of the Company’s reserve estimates. We compared reserve quantity information with the corresponding information used for depletion expense and recalculated the depletion expense for compliance with regulatory standards.

/s/ KPMG LLP

We have served as the Company’s auditor since 2014.

Denver, Colorado
February 24, 2020

## Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Centennial Resource Development, Inc.:

*Opinion on Internal Control Over Financial Reporting*

We have audited Centennial Resource Development, Inc. and subsidiaries' (the Company) 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. 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 the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2020 expressed an unqualified opinion on those consolidated 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 Annual Report on 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ KPMG LLP

Denver, Colorado

February 24, 2020

**CENTENNIAL RESOURCE DEVELOPMENT, INC.**
**CONSOLIDATED BALANCE SHEETS**
**(in thousands, except share and per share amounts)**

| | December 31, 2019 | December 31, 2018 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 10,223 | $ 18,157 |
| Accounts receivable, net | 101,912 | 100,623 |
| Derivative instruments | — | 1,632 |
| Prepaid and other current assets | 7,994 | 9,777 |
| Total current assets | 120,129 | 130,189 |
| Property and equipment | | |
| Oil and natural gas properties, successful efforts method | | |
| Unproved properties | 1,470,903 | 1,680,065 |
| Proved properties | 3,962,175 | 2,895,280 |
| Accumulated depreciation, depletion and amortization | (931,737) | (496,900) |
| Total oil and natural gas properties, net | 4,501,341 | 4,078,445 |
| Other property and equipment, net | 14,612 | 8,837 |
| Total property and equipment, net | 4,515,953 | 4,087,282 |
| Noncurrent assets | | |
| Operating lease right-of-use assets | 11,841 | — |
| Other noncurrent assets | 40,365 | 42,550 |
| TOTAL ASSETS | $ 4,688,288 | $ 4,260,021 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities | | |
| Accounts payable and accrued expenses | $ 244,309 | $ 240,575 |
| Derivative instruments | 325 | 6,051 |
| Operating lease liabilities | 9,232 | — |
| Other current liabilities | 600 | 1,090 |
| Total current liabilities | 254,466 | 247,716 |
| Noncurrent liabilities | | |
| Long-term debt, net | 1,057,389 | 691,630 |
| Asset retirement obligations | 16,874 | 13,895 |
| Deferred income taxes | 85,504 | 62,167 |
| Operating lease liabilities | 3,354 | — |
| Other long-term liabilities | — | 744 |
| Total liabilities | 1,417,587 | 1,016,152 |
| Commitments and contingencies (Note 13) | | |
| Shareholders’ equity | | |
| Preferred stock, $.0001 par value, 1,000,000 shares authorized: | | |
| Series A: 1 share issued and outstanding | — | — |
| Common stock, $0.0001 par value, 620,000,000 shares authorized: | | |
| Class A: 280,650,341 shares issued and 275,811,346 shares outstanding at December 31, 2019 and 265,859,273 shares issued and 264,323,328 shares outstanding at December 31, 2018 | 28 | 27 |
| Class C (Convertible): 1,034,119 and 12,003,183 shares issued and outstanding at December 31, 2019 and December 31, 2018, respectively | — | 1 |
| Additional paid-in capital | 2,975,756 | 2,833,611 |
| Retained earnings | 282,336 | 266,538 |
| Total shareholders’ equity | 3,258,120 | 3,100,177 |
| Noncontrolling interest | 12,581 | 143,692 |
| Total equity | 3,270,701 | 3,243,869 |
| TOTAL LIABILITIES AND EQUITY | $ 4,688,288 | $ 4,260,021 |

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

# CENTENNIAL RESOURCE DEVELOPMENT, INC.
## CONSOLIDATED STATEMENTS OF OPERATIONS
### (in thousands, except per share data)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| Operating revenues | | | |
| Oil and gas sales | $ 944,330 | $ 891,045 | $ 429,902 |
| Operating expenses | | | |
| Lease operating expenses | 145,976 | 83,313 | 41,336 |
| Severance and ad valorem taxes | 63,200 | 56,523 | 23,173 |
| Gathering, processing and transportation expenses | 72,834 | 57,624 | 34,259 |
| Depreciation, depletion and amortization | 444,243 | 326,462 | 161,628 |
| Impairment and abandonment expense | 47,245 | 11,136 | (29) |
| Exploration expense | 11,390 | 9,968 | 14,373 |
| General and administrative expenses | 79,156 | 63,304 | 49,882 |
| Total operating expenses | 864,044 | 608,330 | 324,622 |
| Net gain (loss) on sale of long-lived assets | (857) | 475 | 8,796 |
| Income from operations | 79,429 | 283,190 | 114,076 |
| Other income (expense) | | | |
| Interest expense | (55,991) | (26,358) | (5,729) |
| Net gain (loss) on derivative instruments | (1,561) | 15,336 | 5,138 |
| Other income | 334 | 8 | — |
| Total other income (expense) | (57,218) | (11,014) | (591) |
| Income before income taxes | 22,211 | 272,176 | 113,485 |
| Income tax expense | (5,797) | (59,440) | (29,930) |
| Net income | 16,414 | 212,736 | 83,555 |
| Less: Net income attributable to noncontrolling interest | (616) | (12,837) | (7,987) |
| Net income attributable to Class A Common Stock | $ 15,798 | $ 199,899 | $ 75,568 |
| Income per share of Class A Common Stock: | | | |
| Basic | $ 0.06 | $ 0.76 | $ 0.32 |
| Diluted | $ 0.06 | $ 0.75 | $ 0.32 |

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

**CENTENNIAL RESOURCE DEVELOPMENT, INC.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| **Cash flows from operating activities:** | | | |
| Net income | $ 16,414 | $ 212,736 | $ 83,555 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 444,243 | 326,462 | 161,628 |
| Stock-based compensation expense | 28,997 | 20,670 | 13,759 |
| Impairment and abandonment expense | 47,245 | 11,136 | (29) |
| Exploratory dry hole costs | — | 528 | 5,658 |
| Deferred tax expense | 5,797 | 59,440 | 29,930 |
| Net (gain) loss on sale of long-lived assets | 857 | (475) | (8,796) |
| Non-cash portion of derivative (gain) loss | (4,094) | 5,274 | (5,805) |
| Amortization of debt issuance costs and discount | 2,861 | 1,749 | 887 |
| Changes in operating assets and liabilities: | | | |
| (Increase) decrease in accounts receivable | (10,098) | (33,001) | (43,553) |
| (Increase) decrease in prepaid and other assets | (1,882) | (1,168) | (4,088) |
| Increase (decrease) in accounts payable and other liabilities | 33,833 | 66,660 | 26,772 |
| Net cash provided by operating activities | 564,173 | 670,011 | 259,918 |
| **Cash flows from investing activities:** | | | |
| Acquisition of oil and natural gas properties | (103,709) | (212,513) | (435,547) |
| Drilling and development capital expenditures | (855,153) | (998,242) | (574,334) |
| Purchases of other property and equipment | (8,857) | (6,058) | (4,921) |
| Proceeds from sales of oil and natural gas properties | 34,730 | 148,149 | 22,496 |
| Net cash used in investing activities | (932,989) | (1,068,664) | (992,306) |
| **Cash flows from financing activities:** | | | |
| Issuance of Class A common stock | — | — | 340,750 |
| Underwriting discount and offering costs | — | — | (7,291) |
| Proceeds from borrowings under revolving credit facility | 595,000 | 475,000 | 275,000 |
| Repayment of borrowings under revolving credit facility | (720,000) | (175,000) | (275,000) |
| Proceeds from issuance of Senior Notes | 496,175 | — | 400,000 |
| Debt issuance costs | (7,200) | (5,157) | (9,472) |
| Proceeds from exercise of stock options | — | 982 | 877 |
| Restricted stock used for tax withholdings | (1,038) | (1,665) | (644) |
| Net cash provided by financing activities | 362,937 | 294,160 | 724,220 |
| Net increase (decrease) in cash, cash equivalents and restricted cash | (5,879) | (104,493) | (8,168) |
| Cash, cash equivalents and restricted cash, beginning of period | 21,422 | 125,915 | 134,083 |
| **Cash, cash equivalents and restricted cash, end of period** | $ 15,543 | $ 21,422 | $ 125,915 |

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

**CENTENNIAL RESOURCE DEVELOPMENT, INC.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)**
**(in thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2019** | **2018** | **2017** |
| Supplemental cash flow information | | | |
| Cash paid for interest | $ 48,905 | $ 18,284 | $ 4,280 |
| Operating lease liability payments: | | | |
| Cash used in operating activities | 16,774 | — | — |
| Cash used in investing activities | 20,905 | — | — |
| Supplemental non-cash activity | | | |
| Accrued capital expenditures included in accounts payable and accrued expenses | $ 97,090 | $ 119,492 | $ 126,480 |
| Asset retirement obligations incurred, including revisions to estimates | 2,262 | 1,451 | 4,044 |
| Right-of-use assets recognized with offsetting operating lease liabilities | 34,833 | — | — |

Reconciliation of cash, cash equivalents and restricted cash presented in the Consolidated Statements of Cash Flows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2019** | **2018** | **2017** |
| Cash and cash equivalents | $ 10,223 | $ 18,157 | $ 117,315 |
| Restricted cash [(1)] | 5,320 | 3,265 | 8,600 |
| Total cash, cash equivalents and restricted cash | $ 15,543 | $ 21,422 | $ 125,915 |

(1) Included in *Prepaid and other current assets* and *Other noncurrent assets* line items in the Consolidated Balance Sheets.

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

# CENTENNIAL RESOURCE DEVELOPMENT, INC.
## CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
### (in thousands)

| | Common Stock | | | | Preferred Stock | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Class A | | Class C | | Series A | | Series B | | | | | | |
| | Shares | Amount | Shares | Amount | Shares | Amount | Shares | Amount | Additional Paid-In Capital | Retained Earnings (Accumulated Deficit) | Total Shareholder's Equity | Non-controlling Interest | Total Equity |
| Balance at December 31, 2016 | 201,092 | $ 20 | 19,156 | $ 2 | — | $ — | 104 | $ — | $2,364,049 | $ (8,929) | $2,355,142 | $197,793 | $2,552,935 |
| Warrants exercised | 6,236 | 1 | — | — | — | — | — | — | (1) | — | — | — | — |
| Restricted stock issued | 902 | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock forfeited | (12) | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock used for tax withholding | (33) | — | — | — | — | — | — | — | (644) | — | (644) | — | (644) |
| Option exercises | 58 | — | — | — | — | — | — | — | 877 | — | 877 | — | 877 |
| Conversion of Series B preferred shares to Class A common stock | 26,100 | 3 | — | — | — | — | (104) | — | (3) | — | — | — | — |
| Sale of unregistered Class A common stock | 23,500 | 2 | — | — | — | — | — | — | 340,748 | | 340,750 | — | 340,750 |
| Underwriters' discount and offering expense | — | — | — | — | — | — | — | — | (7,291) | — | (7,291) | — | (7,291) |
| Stock-based compensation | — | — | — | — | — | — | — | — | 13,759 | | 13,759 | | 13,759 |
| Change in equity due to issuance of shares by CRP | — | — | — | — | — | — | — | — | (2,682) | — | (2,682) | 2,682 | — |
| Conversion of common stock from Class C to Class A, net of tax | 3,495 | — | (3,495) | — | — | — | — | — | 58,746 | — | 58,746 | (38,715) | 20,031 |
| Net income | — | — | — | — | — | — | — | — | — | 75,568 | 75,568 | 7,987 | 83,555 |
| Balance at December 31, 2017 | 261,338 | 26 | 15,661 | 2 | — | — | — | — | 2,767,558 | 66,639 | 2,834,225 | 169,747 | 3,003,972 |
| Restricted stock issued | 1,030 | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock forfeited | (136) | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock used for tax withholding | (91) | — | — | — | — | — | — | — | (1,665) | — | (1,665) | — | (1,665) |
| Option exercises | 60 | — | — | — | — | — | — | — | 982 | — | 982 | — | 982 |
| Stock-based compensation | — | — | — | — | — | — | — | — | 20,670 | — | 20,670 | — | 20,670 |
| Conversion of common stock from Class C to Class A, net of tax | 3,658 | 1 | (3,658) | (1) | — | — | — | — | 46,066 | — | 46,066 | (38,892) | 7,174 |
| Net income | — | — | — | — | — | — | — | — | — | 199,899 | 199,899 | 12,837 | 212,736 |
| Balance at December 31, 2018 | 265,859 | 27 | 12,003 | 1 | — | — | — | — | 2,833,611 | 266,538 | 3,100,177 | 143,692 | 3,243,869 |
| Restricted stock issued | 4,109 | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock forfeited | (116) | — | — | — | — | — | — | — | — | — | — | — | — |
| Restricted stock used for tax withholding | (171) | — | — | — | — | — | — | — | (1,038) | — | (1,038) | — | (1,038) |
| Stock-based compensation | — | — | — | — | — | — | — | — | 28,997 | — | 28,997 | — | 28,997 |
| Conversion of common stock from Class C to Class A, net of tax | 10,969 | 1 | (10,969) | (1) | — | — | — | — | 114,186 | — | 114,186 | (131,727) | (17,541) |
| Net income | — | — | — | — | — | — | — | — | — | 15,798 | 15,798 | 616 | 16,414 |
| Balance at December 31, 2019 | 280,650 | $ 28 | 1,034 | $ — | — | $ — | — | $ — | $2,975,756 | $ 282,336 | $3,258,120 | $ 12,581 | $3,270,701 |

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

**Note 1—Basis of Presentation and Summary of Significant Accounting Policies**

***Description of Business***

Centennial Resource Development, Inc. is an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The Company's assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, and its properties consist of large, contiguous acreage blocks located in West Texas and New Mexico. Unless otherwise specified or the context otherwise requires, all references in these notes to "Centennial" or the "Company" are to Centennial Resource Development, Inc. and its consolidated subsidiary, Centennial Resource Production, LLC ("CRP").

***Principles of Consolidation and Basis of Presentation***

The consolidated financial statements include the accounts of the Company and its majority owned subsidiary CRP, and CRP's wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and the rules and regulations of the United States Securities and Exchange Commission ("SEC"). All intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interests represent third-party ownership in CRP, and it is presented as a component of equity. See *Note 9—Shareholders' Equity and Noncontrolling Interest* for discussion on noncontrolling interest.

Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

***Use of Estimates***

The preparation of the Company's consolidated financial statements requires the Company's management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events, and accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments and estimates include: (i) oil and natural gas reserves; (ii) cash flow estimates used in impairment tests of long-lived assets; (iii) impairment expense of unproved properties; (iv) depreciation, depletion and amortization; (v) asset retirement obligations; (vi) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (vii) accrued revenues and related receivables; (viii) accrued liabilities; (ix) valuation of derivatives; and (x) deferred income taxes.

***Cash and Cash Equivalents and Restricted Cash***

The Company considers all highly liquid instruments with an original maturity of three months or less at the time of issuance to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short-term maturity of these investments. From time to time, the Company is required to maintain cash in separate accounts, the use of which is restricted by the terms of contracted arrangements. Such amounts are included in *Prepaid and other current assets* and *Other noncurrent assets* as of December 31, 2019 and December 31, 2018 in the Consolidated Balance Sheets.

***Accounts Receivable***

Accounts receivable consists mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Accordingly, the Company's oil and natural gas receivables are generally collected, and the Company has minimal bad debts.

Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized, and the Company therefore establishes an allowance for doubtful accounts equal to the portions of its accounts receivable for which collectability is not reasonably assured. The Company had $0.1 million in allowance for doubtful accounts as of December 31, 2019 and none as of December 31, 2018.

***Credit Risk and Other Concentrations***

Centennial is exposed to credit risk in the event of nonpayment by counterparties. The Company normally sells production to a relatively small number of customers, as is customary in its business. The table below presents percentages by purchaser that accounted for 10% or more of the Company's total net revenues for each year as presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| BP America | 37% | 18% | 16% |
| ExxonMobil Oil Corporation | 26% | —% | —% |
| Shell Trading (US) Company | 11% | 19% | 33% |
| Eagleclaw Midstream Ventures, LLC | 8% | 12% | 14% |

During these periods, no other purchaser accounted for 10% or more of the Company's net revenues. The loss of any of the Company's major purchasers could materially and adversely affect its revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, the Company believes that the loss of any major purchaser would not have a material adverse effect on its financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company also exposes itself to credit risk. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; and (ii) only entering into hedging arrangements with counterparties that are also participants in CRP's credit agreement, all of which have investment-grade credit ratings.

***Oil and Natural Gas Properties***

The Company's oil and natural gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete development wells are capitalized to proved properties. Exploration costs, including personnel and other internal costs, geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Costs of drilling exploratory wells, on the other hand, are initially capitalized but are charged to expense if the well is determined to be unsuccessful. Costs to operate, repair and maintain wells and field equipment are expensed as incurred.

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in process to bring the projects to their intended use. Capitalized interest cannot exceed interest expense for the period capitalized. The Company capitalized interest of $4.1 million, $2.9 million and $1.2 million during the years ended December 31, 2019, 2018 and 2017, respectively.

*Proved Properties.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, natural gas and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, extension wells and service wells, are capitalized. Capitalized proved property acquisition and development costs are depleted using a units-of production method based on the remaining life of proved and proved developed reserves, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized. Gains or losses from the disposal of complete units of depreciable property are recognized to the Consolidated Statements of Operations.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that there could be a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted 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, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital and operating expenditures and discount rates, which are based on a weighted average cost of capital. There were no impairments of proved oil and natural gas properties for the years ended December 31, 2019, 2018 and 2017.

*Unproved Properties.* Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves, and they are both capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or a right in a property such as a lease, in addition to broker fees, recording fees and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered on or otherwise attributed to the property, at which time the related unproved property costs are transferred to proved oil and natural gas properties.

The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or changes in future plans to develop acreage. Unproved properties that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on the Company's historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of unproved properties are included in *Impairment and abandonment expense* in the Consolidated Statements of Operations.

***Other Property and Equipment***

Other property and equipment includes office furniture and equipment, buildings, vehicles, computer hardware and software and is recorded at cost. These assets are depreciated using the straight-line method over their estimated useful lives which range from three to twenty years. Equipment upgrades and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts and a gain or loss is recorded in the Consolidated Statements of Operations as needed.

***Debt Issuance Costs and Discount***

Debt issuance costs related to the Company's revolving credit facility are included in the line item *Other Noncurrent Assets* in the Consolidated Balance Sheets. These costs are amortized to interest expense on a straight-line basis over the borrowing term. Issuance costs incurred in connection with the Company's Senior Notes offerings and any related issuance discount are deferred and charged to interest expense over the term of the agreement; however, these amounts are reflected as a reduction of the related obligation in the line item *Long-term debt* on the Consolidated Balance Sheets.

***Derivative Financial Instruments***

In order to mitigate its exposure to oil and natural gas price volatility, the Company may periodically use derivative instruments, such as swaps, costless collars, basis swaps, and other similar agreements. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis.

The Company records derivative instruments in its Consolidated Balance Sheets as either an asset or liability measured at fair value. The commodity derivative instruments are accounted for using mark-to-market accounting where all gains and losses are recognized in earnings during the period in which they are incurred. The Company's derivatives have not been designated as hedges for accounting purposes.

***Asset Retirement Obligations***

The Company recognizes a liability for the estimated future costs associated with abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired. The fair value of the liability recognized is based on the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The Company depletes the amount added to proved oil and natural gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

***Revenue Recognition***

The Company derives revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when a performance obligation is satisfied by transferring control of the produced oil, natural gas or NGLs to the customer. For all commodity products, the Company records revenue in the month production is delivered to the purchaser based on estimates of the amount of production delivered to the purchaser and the price the Company will receive. Payments are generally received between 30 and 90 days after the date of production. Variances between estimated sales and actual amounts received are insignificant and are recorded in the month payment is received. Refer to *Note 14—Revenues* for additional information.

***Income Taxes***

Income taxes are recognized based on earnings reported for tax return purposes and provisions recorded for deferred income taxes. Deferred income tax assets and liabilities are recognized based on temporary differences resulting from: (i) net operating loss carryforwards for income tax purposes, and (ii) differences between the amounts recorded to the consolidated financial statements and the tax basis of assets and liabilities, as measured using enacted statutory tax rates in effect at the end of a period. The effect of a change in tax rates or tax laws is recognized in income during the period such changes are enacted. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized.

***Stock-Based Compensation***

The Company's stock-based compensation consists of grants of restricted stock, stock options, and performance stock units to employees and directors, as well as an employee stock purchase plan which is available to eligible employees. The Company determines compensation expense related to all stock-based awards based on their estimated grant-date fair value, and such expense is recognized on a straight-line basis over the applicable service period of the award. See *Note 6—Stock-Based Compensation* for additional information regarding the Company's stock-based compensation.

***Earnings (Loss) Per Share***

Basic earnings per share ("EPS") is calculated by dividing net income available to Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Dilutive EPS is calculated by dividing adjusted net income available to Class A Common Stock by the weighted average number of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. See *Note 10—Earnings Per Share* for additional information regarding the Company's computation of EPS.

***Segment Reporting***

The Company operates in only one industry segment which is the exploration and production of oil and natural gas. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

***Recently Issued or Adopted Accounting Standards***

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, *Leases*, which created Accounting Standard Codification ("ASC") Topic 842, *Leases* ("ASC Topic 842"), superseding current lease requirements under ASC Topic 840, *Leases*. Subsequently in 2018, the FASB issued various ASUs which provide a practical expedient for the evaluation of existing land easement agreements, optionality in the adoption transition method, and additional implementation guidance. ASC Topic 842 and its related amendments apply to any entity that enters into a lease, with some specified scope exemptions. Under ASC Topic 842, a lessee should recognize in its consolidated balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset, representing its right to use the underlying asset for the lease term. While there were no major changes to lessor accounting, changes were made to align key aspects with revenue recognition guidance. ASC Topic 842 was effective for public entities for fiscal years, beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted.

The standard permits retrospective application using either of the following methodologies: (i) application of the new standard at the earliest presented period or (ii) application of the new standard at the adoption date with a cumulative-effect adjustment recognized to retained earnings. The Company has adopted this guidance as of January 1, 2019 and elected to recognize a cumulative-effect adjustment at the time of adoption. The Company has elected the following practical expedients that allow an entity to carry forward historical accounting treatment relating to: (i) lease identification and classification for existing leases and (ii) existing land easements. The adoption of ASC 842 resulted in the recognition of *Operating lease right-of-use assets* and *Operating lease liabilities* in the Company's Consolidated Balance Sheets for its existing operating leases including drilling rig contracts, office rental agreements, and other wellhead equipment. This adoption did not have a significant impact on the Company's Consolidated Statements of Operations or Consolidated Statements of Cash Flows. Refer to *Note 15—Leases* for additional information.

**Note 2—Property Acquisitions and Divestitures**

***2018 Acquisitions***

On February 8, 2018, the Company completed the acquisition of approximately 4,000 undeveloped net acres, as well as certain producing properties, in Lea County, New Mexico for an unadjusted purchase price of $94.7 million. The operated acreage position contains an approximate 92% average working interest and is largely contiguous to Centennial’s existing positions in the northern Delaware Basin.

During the fourth quarter of 2018, the Company completed several acquisitions totaling approximately 2,900 net acres, which are located adjacent to the Company’s existing acreage in Lea County, New Mexico and Reeves County, Texas for an aggregate unadjusted purchase price of $87.9 million. This value encompasses certain producing properties included in the acquisitions.

All acquisitions during 2018 were recorded as asset acquisitions under ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business (“ASC 2017-11”)*. Accordingly, the purchase consideration for these assets has been allocated to the oil and natural gas properties based on their relative fair values measured as of the acquisition dates. After aggregate settlement statement adjustments of $0.3 million, the Company paid an aggregate purchase price of $182.3 million. On a relative fair value basis, $142.5 million was allocated to unproved properties and $39.8 million to proved properties. Transaction costs incurred and capitalized amounted to $0.2 million and mainly consisted of advisory and legal fees.

***2018 Disposition***

On March 2, 2018, the Company completed the sale of approximately 8,600 undeveloped net acres and 12 gross producing wells located in Reeves County, Texas for a total unadjusted sales price of $140.7 million. The divested acreage represents a largely non-operated position (32% average working interest) on the western portion of Centennial’s position in Reeves County. There was no gain or loss recognized as a result of this divestiture, which constituted a partial sale of oil and gas properties in accordance with ASC 932, *Extractive Activities - Oil and Gas*. The Company used the net proceeds from the sale to fund the 2018 acquisitions discussed above.

***2017 Acquisition***

On June 8, 2017, the Company completed the GMT Acquisition and acquired interests in 36 gross producing horizontal wells plus undeveloped acreage on approximately 11,850 net acres (14,770 gross acres) in Lea County, New Mexico for an unadjusted purchase price of $350.0 million. The Company operates approximately 79% of, and has an approximate 85% average working interest in, this acreage. The acquired acres are located in the Northern Delaware Basin with drilling locations in the Avalon Shale, 2nd Bone Spring Sand, 3rd Bone Spring Sand and Wolfcamp A formations.

The GMT Acquisition was recorded as an asset acquisition under ASU 2017-01. Accordingly, the GMT purchase consideration has been allocated to the GMT oil and natural gas properties based on their relative fair values measured as of the acquisition date. After settlement statement adjustments of $0.1 million, the Company paid a net purchase price of $350.1 million. On a relative fair value basis, $296.9 million was allocated to unproved properties and $53.2 million to proved properties. Transaction costs as they relate to the GMT Acquisition mainly consist of advisory, legal and accounting fees and are capitalized as incurred, and the Company has incurred $0.5 million in transaction costs related to this acquisition.

**Note 3—Accounts Receivable, Accounts Payable and Accrued Expenses**

Accounts receivable are comprised of the following:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| Accrued oil and gas sales receivable, net | $ 76,578 | $ 66,997 |
| Joint interest billings, net | 25,136 | 31,658 |
| Other | 198 | 1,968 |
| Accounts receivable, net | $ 101,912 | $ 100,623 |

Accounts payable and accrued expenses are comprised of the following:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| Accounts payable | $ 21,484 | $ 55,984 |
| Accrued capital expenditures | 83,002 | 75,791 |
| Revenues payable | 82,539 | 63,399 |
| Accrued employee compensation and benefits | 12,979 | 9,757 |
| Accrued interest | 19,405 | 11,129 |
| Accrued expenses and other | 24,900 | 24,515 |
| Accounts payable and accrued expenses | $ 244,309 | $ 240,575 |

## Note 4—Long-Term Debt

The following table provides information about the Company's long-term debt as of the dates indicated:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| Credit Facility due 2023 | $ 175,000 | $ 300,000 |
| | | |
| 5.375% Senior Notes due 2026 | 400,000 | 400,000 |
| 6.875% Senior Notes due 2027 | 500,000 | — |
| Unamortized debt issuance costs on Senior Notes | (14,061) | (8,370) |
| Unamortized debt discount | (3,550) | — |
| Senior Notes, net | 882,389 | 391,630 |
| | | |
| Total long-term debt, net | $ 1,057,389 | $ 691,630 |

***Credit Agreement***

On May 4, 2018, CRP, the Company's consolidated subsidiary, entered into an amended and restated credit agreement with a syndicate of banks that as of December 31, 2019, had a borrowing base of $1.2 billion and elected commitments of $800.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of December 31, 2019, the Company had $175.0 million in borrowings outstanding and $624.2 million in available borrowing capacity, which was net of $0.8 million in letters of credit outstanding.

The amount available to be borrowed under the CRP's credit agreement is equal to the lesser of (i) the borrowing base, (ii) aggregate elected commitments, or (iii) $1.5 billion. The borrowing base is redetermined semi-annually in the spring and fall by the lenders in their sole discretion. It also allows for two optional borrowing base redeterminations on January 1 and July 1. The borrowing base depends on, among other things, the quantities of CRP's proved oil and natural gas reserves, estimated cash flows from these reserves, and the Company's commodity hedge positions. Upon a redetermination of the borrowing base, if actual borrowings exceed the revised borrowing capacity, CRP could be required to immediately repay a portion of its debt outstanding under the credit agreement. Borrowings under CRP's revolving credit facility are guaranteed by certain of its subsidiaries. In connection with the credit facility's fall 2019 semi-annual borrowing base redetermination, the borrowing base was reaffirmed at $1.2 billion and the amount of elected commitments remained at $800.0 million.

Borrowings under CRP's revolving credit facility may be base rate loans or LIBOR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for LIBOR loans. LIBOR loans bear interest at LIBOR (adjusted for statutory reserve requirements) plus an applicable margin, which ranged from 125 to 225 basis points as of December 31, 2019, depending on the percentage of the borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; or (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin, which ranged 25 to 125 basis points as of December 31, 2019, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee of 37.5 to 50 basis points on unused amounts under its facility. The applicable margins for the LIBOR loans and base rate loans referenced above reflect interest rate reductions that became effective on April 26, 2019 and are applicable as long as CRP's total leverage ratio (as described below) is less than or equal to 3.0 to 1.0. If CRP'S leverage ratio exceeds 3.0 to 1.0 in the future, the original applicable margins under the credit agreement would revert to the range from 150 to 250 basis points for LIBOR loans and 50 to 150 basis points for base rate loans, in each case depending on the percentage of the borrowing base utilized. The weighted-average borrowing rate on the credit agreement, exclusive of unused commitment fees and the letter of credit noted above, was 3.7% and 3.8% per annum for the years ended December 31, 2019 and 2018, respectively.

CRP's credit agreement contains restrictive covenants that limit its ability to, among other things: (i) incur additional indebtedness; (ii) make investments and loans; (iii) enter into mergers; (iv) make or declare dividends; (v) enter into commodity hedges exceeding a specified percentage of the Company's expected production; (vi) enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness; (vii) incur liens; (viii) sell assets; and (ix) engage in transactions with affiliates.

CRP's credit agreement also requires it to maintain compliance with the following financial ratios: (i) a current ratio, which is the ratio of CRP's consolidated current assets (including unused commitments under its revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the credit agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with these covenants and the financial ratios described above as of December 31, 2019 and through the filing of this Annual Report.

***Senior Unsecured Notes***

On March 15, 2019, CRP issued $500.0 million of 6.875% senior notes due 2027 (the "2027 Senior Notes") in a 144A private placement at a price equal to 99.235% of par that resulted in net proceeds to CRP of $489.0 million, after deducting the original issuance discount of $3.8 million and debt issuance costs of $7.2 million. Interest is payable on the 2027 Senior Notes semi-annually in arrears on each April 1 and October 1, which commenced on October 1, 2019.

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (the "2026 Senior Notes" and collectively with the 2027 Senior Notes, the "Senior Notes") in an 144A private placement that resulted in net proceeds to CRP of $391.0 million, after deducting $9.0 million in debt issuance costs. Interest is payable on the 2026 Senior Notes semi-annually in arrears on each January 15 and July 15, which commenced on July 15, 2018.

The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of CRP's current subsidiaries that guarantee CRP's revolving credit facility. The Senior Notes are not guaranteed by the Company, nor is the Company subject to the terms of the indenture governing the Senior Notes.

At any time prior to January 15, 2021 (for the 2026 Senior Notes) and April 1, 2022 (for the 2027 Senior Notes), the "Optional Redemption Dates," CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of either series of Senior Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.375% (for the 2026 Senior Notes) and 106.875% (for the 2027 Senior Notes) of the principal amount of the Senior Notes of the applicable series redeemed, plus accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount of each such series of Senior Notes remains outstanding immediately after such redemption, and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to Optional Redemption Dates, CRP may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100% of the principal amount of the Senior Notes redeemed, plus a "make-whole" premium, and any accrued and unpaid interest as of the date of redemption. On and after the Optional Redemption Dates, CRP may redeem the Senior Notes, in whole or in part, at redemption prices expressed as percentages of principal amount plus accrued and unpaid interest to the redemption date.

If CRP experiences certain defined changes of control (and in certain cases followed by a ratings decline), each holder of the Senior Notes may require CRP to repurchase all or a portion of its Senior Notes for cash at a price equal to 101% of the aggregate principal amount of such Senior Notes, plus any accrued and unpaid interest to the date of repurchase.

The indentures governing the Senior Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP's ability and the ability of CRP's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of December 31, 2019 and through the filing of this Annual Report.

Upon an Event of Default (as defined in the indentures governing the Senior Notes), the trustee or the holders of at least 25% of the aggregate principal amount of then outstanding Senior Notes may declare the Senior Notes immediately due and payable.

In addition, a default resulting from certain events of bankruptcy or insolvency with respect to CRP, any restricted subsidiary of CRP that is a significant subsidiary, or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary, will automatically cause all outstanding Senior Notes to become due and payable.

**Note 5—Asset Retirement Obligations**

The following table summarizes the changes in the Company's asset retirement obligations ("ARO") associated with its working interests in oil and gas properties for the periods presented:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| Asset retirement obligations, beginning of period | $ 13,895 | $ 12,161 |
| Liabilities incurred | 1,393 | 1,535 |
| Liabilities acquired | 1,167 | 165 |
| Liabilities divested and settled | (1,361) | (673) |
| Accretion expense | 912 | 791 |
| Revisions to estimated cash flows | 868 | (84) |
| Asset retirement obligations, end of period | $ 16,874 | $ 13,895 |

ARO reflect the present value of the estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate plug and abandonment settlement amounts, inflation factors, credit adjusted discount rates and timing of settlement. To the extent future revisions to these assumptions impact the value of the existing ARO liability, a corresponding offsetting adjustment is made to the oil and natural gas property balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as accretion expense.

**Note 6—Stock-Based Compensation**

On October 7, 2016, the stockholders of the Company approved the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the "LTIP"). An aggregate of 16,500,000 shares of Class A Common Stock were authorized for issuance under the LTIP, and as of December 31, 2019, the Company had 4,962,545 shares of Class A Common Stock available for future grants. The LTIP provides for grants of stock options (including incentive stock options and nonqualified stock options), stock appreciation rights, restricted stock, dividend equivalents, restricted stock units and other stock or cash-based awards.

Stock-based compensation expense is recognized within both *General and administrative expenses* and *Exploration expense* in the Consolidated Statements of Operations. The Company accounts for forfeitures of awards granted under the LTIP as they occur in determining compensation expense.

The following table summarizes stock-based compensation expense recognized for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| Restricted stock awards | $ 15,929 | $ 9,185 | $ 5,008 |
| Stock option awards | 9,562 | 9,433 | 8,160 |
| Performance stock units | 3,374 | 2,052 | 591 |
| Other stock-based compensation expense[1] | 132 | — | — |
| Total stock-based compensation expense | $ 28,997 | $ 20,670 | $ 13,759 |

(1) Includes expenses related to the Company's Employees Stock Purchase Plan (the "ESPP"). In May 2019, an aggregate of 2,000,000 shares were authorized by stockholders for issuance under the ESPP, which became effective on July 1, 2019.

***Restricted Stock***

The following table provides a summary of the restricted stock activity during the year ended December 31, 2019:

| | Awards | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Unvested balance as of December 31, 2018 | 1,535,945 | $ 17.88 |
| Granted | 4,109,148 | 6.59 |
| Vested | (690,084) | 17.46 |
| Forfeited | (116,013) | 11.39 |
| Unvested balance as of December 31, 2019 | 4,838,996 | 8.51 |

The Company grants service-based restricted stock awards to executive officers and employees, which vest ratably over a three-year service period, and to directors, which vest over a one-year service period. Compensation cost for these service-based restricted stock awards is based on the market price of the Company's Class A common stock on the grant date, and such costs are recognized ratably over the applicable vesting period. The weighted average grant-date fair value for restricted stock awards granted was $6.59, $18.11 and $17.33 per share for the years ended December 31, 2019, 2018 and 2017, respectively. The total fair value of restricted stock awards that vested for the years ended December 31, 2019, 2018 and 2017 was $12.0 million, $6.6 million and $2.7 million, respectively. Unrecognized compensation cost related to restricted shares that were unvested as of December 31, 2019 was $32.0 million, which the Company expects to recognize over a weighted average period of 2.2 years.

***Stock Options***

Stock options that have been granted under the LTIP expire ten years from the grant date and vest ratably over a three-year service period. The exercise price for an option granted under the LTIP is the closing price of the Company's Class A Common Stock as reported by NASDAQ on the date of grant.

Compensation cost for stock options is based on the grant-date fair value of the award, which is then recognized ratably over the vesting period of three years. The Company estimates the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the weighted average volatility of the Company and an identified set of comparable companies. Expected term is based on the simplified method and is estimated as the mid-point between the weighted average vesting term and the time to expiration as of the grant date. The Company uses U.S. Treasury yield curve rates in effect at the grant date for its risk-free interest rates.

The following table summarizes the assumptions and related information used to determine the grant-date fair value of stock options awarded for the periods presented:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| Weighted average grant date fair value per share | $ 4.32 | $ 8.58 | $ 7.15 |
| Expected term (in years) | 6 | 6 | 6 |
| Expected stock volatility | 47% | 42% | 38% |
| Dividend yield | — | — | — |
| Risk-free interest rate | 2.2% | 2.7% | 2.0% |

The following table provides information about stock option awards outstanding during the year ended December 31, 2019:

| | Options | Weighted Average Exercise Price | Weighted Average Remaining Term (in years) | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding as of December 31, 2018 | 4,559,334 | $ 16.55 | | |
| Granted | 346,500 | 9.24 | | |
| Exercised | — | — | | |
| Forfeited | (103,670) | 17.76 | | |
| Expired | (37,997) | 17.80 | | |
| Outstanding as of December 31, 2019 | 4,764,167 | 15.99 | 7.3 | $ 11 |
| Exercisable as of December 31, 2019 | 3,530,630 | 16.00 | 7.0 | $ — |

The total fair value of stock options that vested during the years ended December 31, 2019, 2018 and 2017 was $10.2 million, $8.8 million and $4.9 million, respectively. The intrinsic value of stock options exercised was approximately $0.2 million for both the years ended December 31, 2018 and 2017. There were no stock options exercised during the year ended December 31, 2019. As of December 31, 2019, there was $4.1 million of unrecognized compensation cost related to unvested stock options, which the Company expects to recognize on a pro-rata basis over a weighted average period of 1.6 years.

***Performance Stock Units***

The Company grants performance stock units to certain executive officers that are subject to market-based vesting criteria as well as a three-year service period. Vesting at the end of the three-year service period is subject to the condition that the Company’s stock price increases by a greater percentage, or decreases by a lesser percentage, than the average percentage increase or decrease, respectively, of the stock prices of a peer group of companies. The market-based conditions must be met in order for the stock awards to vest, and it is, therefore, possible that no shares could vest. However, the Company recognizes compensation expense for the performance stock units subject to market conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

The grant-date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company’s common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

The following table summarizes the key assumptions and related information used to determine the grant-date fair value of performance stock units awarded during the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| Weighted average grant-date fair value per unit | $ 6.68 | $ 22.35 | $ 21.53 |
| Number of simulations | 1,000,000 | 1,000,000 | 1,000,000 |
| Expected stock volatility | 52.3% | 40.2% | 41.6% |
| Dividend yield | —% | —% | —% |
| Risk-free interest rate | 1.8% | 2.8% | 1.5% |

The following table provides information about performance stock units outstanding during the year ended December 31, 2019:

| | Awards | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested balance as of December 31, 2018 | 386,459 | $ 21.94 |
| Granted | 486,213 | 6.68 |
| Vested | — | — |
| Forfeited | — | — |
| Unvested balance as of December 31, 2019 | 872,672 | 13.44 |

As of December 31, 2019, there was $5.7 million of unrecognized compensation cost related to unvested performance stock units, which the Company expects to recognize on a pro rata basis over a weighted average period of 1.9 years

## Note 7—Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations and may use derivative instruments to manage its exposure to commodity price risk from time to time.

***Commodity Derivative Contracts***

Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. The Company may periodically use derivative instruments, such as swaps, costless collars and basis swaps, to mitigate its exposure to declines in commodity prices and to the corresponding negative impacts such declines can have on its cash flow from operations, returns on capital and other financial results. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not enter into derivative contracts for speculative or trading purposes.

*Commodity Swap Contracts.* The Company may opportunistically use commodity derivative instruments known as fixed price swaps to realize a known price for a specific volume of production as well as basis swaps to hedge the difference between the index price and a local index price. All transactions are settled in cash with one party paying the other for the resulting difference in price multiplied by the contract volume.

The following table summarizes the approximate volumes and average contract prices of swap contracts the Company had in place as of December 31, 2019:

| | Period | Volume (Bbl) | Volume (Bbls/d) | Weighted Average Differential ($/Bbl) [1] |
|---|---|---|---|---|
| Crude oil basis swaps | January 2020 - March 2020 | 273,000 | 3,000 | $ 0.67 |
| | April 2020 - June 2020 | 273,000 | 3,000 | 0.67 |
| | July 2020 - September 2020 | 276,000 | 3,000 | 0.67 |
| | October 2020 - December 2020 | 276,000 | 3,000 | 0.67 |

(1) These oil basis swap transactions are settled based on the difference between the arithmetic average of the ARGUS MIDLAND WTI and ARGUS WTI CUSHING indices, during each applicable settlement period.

*Derivative Instrument Reporting.* The Company's oil and natural gas derivative instruments have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's Consolidated Statements of Operations. All derivative instruments are recorded at fair value in the Consolidated Balance Sheets, other than derivative instruments that meet the "normal purchase normal sale" exclusion, and any fair value gains and losses are recognized in current period earnings.

The following table presents the impact of the Company's derivative instruments on its Consolidated Statements of Operations for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| Net gain (loss) on derivative instruments | $ (1,561) | $ 15,336 | $ 5,138 |

*Offsetting of Derivative Assets and Liabilities.* The Company's commodity derivatives are included in the accompanying Consolidated Balance Sheets as derivative assets and liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master netting agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The tables below summarize the fair value amounts and classification in the Consolidated Balance Sheets of the Company's derivative contracts outstanding at the respective balance dates, as well as the gross recognized derivative assets, liabilities and offset amounts:

| (in thousands) | Balance Sheet Classification | Gross Fair Value Asset/Liability Amounts | Gross Amounts Offset [1] | Net Recognized Fair Value Assets/Liabilities |
|---|---|---|---|---|
| | | December 31, 2019 | | |
| **Derivative Liabilities** | | | | |
| Commodity contracts | Current liabilities - Derivative instruments | $ 325 | $ — | $ 325 |
| | | December 31, 2018 | | |
| **Derivative Assets** | | | | |
| Commodity contracts | Current assets - Derivative instruments | $ 7,708 | $ (6,076) | $ 1,632 |
| **Derivative Liabilities** | | | | |
| Commodity contracts | Current liabilities - Derivative instruments | $ 12,127 | $ (6,076) | $ 6,051 |

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset of derivative assets against derivative liabilities at settlement or in the event of a default under the agreements or contract termination.

*Contingent Features in Financial Derivative Instruments.* None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under CRP's credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of any CRP bank debt, which eliminates the potential need to post collateral when Centennial is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

In addition, the Company is exposed to credit risk associated with its derivative contracts from non-performance by its counterparties. The Company mitigates its exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a member of CRP's credit facility as referenced above.

## Note 8—Fair Value Measurements

### *Recurring Fair Value Measurements*

The Company follows FASB ASC Topic 820, *Fair Value Measurement and Disclosure,* which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The following table presents, for each applicable level within the fair value hierarchy, the Company's net derivative assets and liabilities, including both current and noncurrent portions, measured at fair value on a recurring basis:

| (in thousands) | Level 1 | Level 2 | Level 3 |
|---|---|---|---|
| **December 31, 2019** | | | |
| Total assets | $ — | $ — | $ — |
| Total liabilities | — | 325 | — |
| **December 31, 2018** | | | |
| Total assets | $ — | $ 1,632 | $ — |
| Total liabilities | — | 6,051 | — |

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy 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 in its entirety requires judgement and considers factors specific to the asset or liability. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. There were no transfers between any of the fair value levels during any period presented.

***Derivatives***

The Company uses Level 2 inputs to measure the fair value of its oil and natural gas commodity derivatives. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations. Refer to *Note 7—Derivative Instruments* for details of the gross and net derivative assets, liabilities and offset amounts as presented in the Consolidated Balance Sheets.

***Nonrecurring Fair Value Measurements***

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation. Refer to *Note 2—Property Acquisitions and Divestitures* for additional information on the fair value of assets acquired.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include plugging costs and reserve lives. Refer to *Note 5—Asset Retirement Obligations* for additional information on the Company's ARO.

***Other Financial Instruments***

The carrying amounts of the Company's cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate their fair values because of the short-term maturities and/or liquid nature of these assets and liabilities.

The Company's Senior Notes and borrowings under its credit agreement are recorded at cost. The following table summarizes the fair values and carrying values of these instruments as of December 31, 2019 and December 31, 2018:

| | December 31, 2019 | | December 31, 2018 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair value |
| Credit facility due 2023[1] | $ 175,000 | $ 175,000 | $ 300,000 | $ 300,000 |
| 5.375% Senior Notes due 2026[2] | 392,623 | 394,480 | 391,630 | 372,000 |
| 6.875% Senior Notes due 2027[2] | 489,766 | 520,000 | | |

(1) The carrying values of the amounts outstanding under CRP's credit agreement approximate fair value because its variable interest rates are tied to current market rates, and the applicable credit spreads represent current market rates for the credit risk profile of the Company.

(2) The Senior Notes' carrying values include associated unamortized debt issuance costs and any discounts. The Senior Notes' fair values were determined using quoted market prices for these debt securities, a Level 1 classification in the fair value hierarchy.

**Note 9—Shareholders' Equity and Noncontrolling Interest**

During 2019, the legacy owners of CRP (the "Centennial Contributors") exchanged 10,969,064 of their CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock. A tax loss of $17.5 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner. No cash proceeds were received by the Company in connection with this exchange.

On March 7, 2018, Silver Run Sponsor, LLC ("Silver Run Sponsor"), the Riverstone Purchasers and the Centennial Contributors completed an underwritten public offering of 25,000,000 shares of Class A Common Stock. No cash proceeds were received by the Company in connection with this offering and 3,347,647 shares of CRP Common Units (and corresponding shares of Class C Common Units) were converted to shares of Class A Common Stock on a one-to-one basis. A tax benefit of $7.2 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

On November 9, 2017, Silver Run Sponsor, the Riverstone Purchasers and Centennial Contributors completed an underwritten public offering of 25,000,000 shares of Class A Common Stock. No cash proceeds were received by the Company in connection with this offering and 3,494,583 shares of Class C Common Units were converted to shares of Class A Common Stock on a one-to-one basis. In addition, a tax benefit of $20.0 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

On May 25, 2017, the Company's stockholders approved at a special meeting the issuance of 26,100,000 shares of Class A Common Stock upon the conversion of 104,400 shares of Series B Preferred Stock that were held by affiliates of Riverstone Investment Group LLC in a private placement. There were no cash proceeds received by the Company in connection with this issuance.

On May 4, 2017, the Company entered into subscription agreements with certain investors pursuant to which such investors agreed to purchase, in the aggregate, 23,500,000 shares of Class A Common Stock at a purchase price of $14.50 per share, for gross proceeds of approximately $340.8 million. The closing under the subscription agreements occurred concurrently with the closing of the GMT Acquisition on June 8, 2017, and the proceeds were used to fund a majority of the purchase price of that acquisition.

*Class A Common Stock*

Holders of the Company's Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by the Company's stockholders. Holders of the Class A Common Stock and holders of the Class C Common Stock vote together as a single class on all matters submitted to a vote of the Company's stockholders, except as required by law.

Unless specified in the Charter (including any certificate of designation of preferred stock) or Bylaws, or as required by applicable provisions of the Delaware General Corporation Law or applicable stock exchange rules, the affirmative vote of a majority of the Company's shares of common stock that are voted is required to approve any such matter voted on by the Company's stockholders. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors (subject to the right of the holder of the Company's Series A Preferred Stock to nominate and elect one director). Subject to the rights of the holders of any outstanding series of preferred stock, the Company's stockholders are entitled to receive ratable dividends when and if declared by the board of directors out of funds legally available therefor.

In the event of a liquidation, dissolution or winding up of the Company, the holders of the Class A Common Stock are entitled to share ratably in all assets remaining available for distribution to them after payment of liabilities and after provision is made for each class of stock having preference, if any, over the Class A Common Stock. The Company's stockholders have no preemptive or other subscription rights. There are no sinking fund provisions applicable to the Class A Common Stock.

*Class C Common Stock*

The Company had 1,034,119 shares of Class C Common Stock outstanding as of December 31, 2019, which represent the remaining portion of the 20,000,000 shares of Class C Common Stock issued to the Centennial Contributors in connection with the Business Combination that have not been redeemed or exchanged as of such date.

Holders of Class C Common Stock have the right to vote on all matters properly submitted to a vote of the stockholders and vote together as a single class with the holders of Class A Common Stock. In addition, the holders of Class C Common Stock, voting as a separate class, are entitled to approve any amendment, alteration or repeal of any provision of the Company's Charter that would alter or change the powers, preferences or relative, participating, optional, other or special rights of the Class C Common Stock. Holders of Class C Common Stock are not entitled to any dividends from the Company and are not entitled to receive any of its assets in the event of any voluntary or involuntary liquidation, dissolution or winding up of its affairs.

Shares of Class C Common Stock may be issued only to the Centennial Contributors, their respective successors and assigns, as well as any permitted transferees of the Centennial Contributors. A holder of Class C Common Stock may transfer shares of Class C Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such holder's CRP Common Units to such transferee. Holders of Class C Common Stock generally have the right to cause CRP to redeem all or a portion of their CRP Common Units in exchange for shares of the Company's Class A Common Stock or, at CRP's option, an equivalent amount of cash. The Company may, however, at its option, effect a direct exchange of cash or Class A Common Stock for such CRP Common Units in lieu of such a redemption by CRP. Upon the future redemption or exchange of CRP Common Units held by a Centennial Contributor, a corresponding number of shares of Class C Common Stock will be canceled.

*Preferred Stock*

As of December 31, 2019 and 2018, the Company had one share of Series A Preferred Stock outstanding which was issued to Centennial Resource Development, LLC ("CRD") in connection with the Business Combination. NGP X US Holdings, L.P. ("NGP"), as the current holder of the Series A Preferred Stock, is not entitled to any dividends from the Company, but is entitled to preferred distributions in liquidation in the amount of $0.0001 per share of Series A Preferred Stock and has a limited voting right as described below. The Series A Preferred Stock is redeemable by the Company (i) at such time as NGP and its affiliates cease to own, in the aggregate, at least 5,000,000 CRP Common Units and/or shares of Class A Common Stock (as adjusted for stock splits, stock dividends, reorganizations, recapitalizations and other similar transactions), (ii) at any time at NGP's option or (iii) upon a breach by NGP of the transfer restrictions relating to the Series A Preferred Stock. In addition, for so long as the Series A Preferred Stock remains outstanding, NGP will be entitled to nominate one director for election to the Company's board of directors in connection with any vote of the Company's stockholders for the election of directors, and the vote of NGP will be the only vote required to elect such nominee to the Company's board of directors. NGP has declined to exercise its right to nominate and elect a director since May 2019, when the director previously nominated and elected by NGP resigned.

*Warrants*

The Company's Public Warrants were originally issued in connection with the initial public offering of units of Silver Run Acquisition Corporation. On March 1, 2017, the Company delivered a notice of redemption to all holders of its Public Warrants announcing its intention to redeem any Public Warrants that remained unexercised and outstanding after March 31, 2017 for $0.01 per Public Warrant. All of the Company's Public Warrants have been either exercised for shares of Class A Common Stock or redeemed for $0.01 per Public Warrant. As a result of all such Warrants exercised in 2017, the Company issued in aggregate 6,235,790 shares of Class A common stock to holders of Public Warrants.

As of December 31, 2019, 8,000,000 Private Placement Warrants remained outstanding. Private Placement Warrants are non-redeemable so long as they are held by Riverstone or its permitted transferees. Each whole Private Placement Warrant is exercisable for one whole share of Class A Common Stock at a price of $11.50 per share. The warrants became exercisable on March 1, 2017 and will expire five years after the completion of the Business Combination or earlier upon redemption or liquidation.

***Noncontrolling Interest***

The noncontrolling interest relates to CRP Common Units that were issued to the Centennial Contributors in connection with the Business Combination. At the date of the Business Combination, the noncontrolling interest held 10.9% of the ownership in CRP. The noncontrolling interest percentage is affected by various equity transactions such as CRP Common Unit and Class C Common Stock exchanges and Class A Common Stock activities.

As of December 31, 2017, the noncontrolling interest ownership of CRP decreased to 5.7%. The decrease was the result of Class A Common Stock issuance in May and the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock in November as discussed in preceding sections above.

As of December 31, 2019 and December 31, 2018, the noncontrolling interest ownership of CRP decreased to 0.37% and 4.3%, respectively. The decreases were mainly the result of the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock.

The Company has consolidated the financial position, results of operations and cash flows of CRP and reflected that portion retained by other holders of CRP Common Units as a noncontrolling interest. Refer to the Consolidated Statements of Shareholders' Equity for a summary of the activity attributable to the noncontrolling interest during the periods.

**Note 10—Earnings Per Share**

Basic EPS is calculated by dividing net income available to Class A Common Stock by the weighted average shares of Class A Common Stock outstanding during each period. Dilutive EPS is calculated by dividing adjusted net income available to Class A Common Stock by the weighted average number of diluted Class A Common Stock outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted EPS calculation consists of (i) unvested restricted stock and performance stock units, outstanding stock options, withholding amounts from employee stock purchase plan and warrants using the treasury stock method, and (ii) the Company's Class C common stock using the "if-converted" method, which is net of tax. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and therefore excluded from the computation of diluted earnings per share.

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings.

Shares of the Company's unvested restricted stock and performance stock units are eligible to receive dividends; however, dividend rights will be forfeited if the award does not vest. Accordingly, these shares are not considered participating securities. Shares of the Company's Class C Common Stock and warrants do not share in earnings or losses and are therefore not participating securities. All of the Company's shares of Series B Preferred Stock were converted into shares of Class A Common Stock on May 25, 2017 in accordance with their terms. As such, the Company no longer has any participating securities as of December 31, 2017 and thereafter.

The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands, except per share data)** | **2019** | **2018** | **2017** |
| Net income attributable to Class A Common Stock | $ 15,798 | $ 199,899 | $ 75,568 |
| Add: Income from conversion of Class C Common Stock | 328 | — | — |
| Adjusted net income attributable to Class A Common Stock | $ 16,126 | $ 199,899 | $ 75,568 |
| | | | |
| Basic net earnings per share of Class A Common Stock | $ 0.06 | $ 0.76 | $ 0.32 |
| Diluted net earnings per share of Class A Common Stock | $ 0.06 | $ 0.75 | $ 0.32 |
| | | | |
| Basic weighted average shares of Class A Common Stock outstanding | 267,700 | 263,341 | 235,447 |
| Add: Dilutive effects of conversion of Class C Common Stock | 8,869 | — | — |
| Add: Dilutive effects of potential common stock | 63 | 3,514 | 4,307 |
| Diluted weighted average shares of Class A Common Stock outstanding | 276,632 | 266,855 | 239,754 |

The following table presents shares were excluded from the diluted earnings per share calculation as their impacts were anti-dilutive for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| Out-of-the-money stock options | 4,706 | 818 | 819 |
| Restricted stock | 2,895 | — | — |
| Performance stock units | — | 39 | — |
| Employee Stock Purchase Plan | 22 | — | — |
| Weighted average shares of Class C Common Stock | — | 12,791 | 18,629 |
| Warrants | 8,000 | — | — |

## Note 11—Income Taxes

The Company is subject to U.S. federal, state and local income taxes with respect to its allocable share of any taxable income or loss of CRP, as well as any stand-alone income or loss generated by the Company. CRP is treated as a partnership for U.S. federal and most applicable state and local income tax purposes. As a partnership, CRP is not subject to U.S. federal and certain state and local income taxes. Any taxable income or loss generated by CRP is passed through to and included in the taxable income or loss of its members, including the Company, on a pro rata basis.

Income tax expenses and benefits included in the Consolidated Statements of Operations are detailed below:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| **Current taxes** | | | |
| Federal | $ — | $ — | $ — |
| State | — | — | — |
| | — | — | — |
| **Deferred taxes** | | | |
| Federal | (5,396) | (56,365) | (26,713) |
| State | (401) | (3,075) | (3,217) |
| | (5,797) | (59,440) | (29,930) |
| Income tax benefit (expense) | $ (5,797) | $ (59,440) | $ (29,930) |

A reconciliation of the statutory federal income tax expense, which is calculated at the federal statutory rate of 21% in 2019 and 2018 and 35% in 2017, to the income tax expense from continuing operations provided for the periods presented, is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| Income tax expense at the federal statutory rate | $ (4,646) | $ (57,157) | $ (39,720) |
| State income tax expense - net of federal income tax benefits | (401) | (3,075) | (2,788) |
| Change in Federal tax rate (net of state benefit) | — | — | 4,425 |
| Noncontrolling interest in partnership | 129 | 2,696 | 2,795 |
| Equity based compensation | (780) | (1,825) | 241 |
| Nondeductible expenses | (99) | (79) | (31) |
| Change in valuation allowance | — | — | 5,148 |
| Income tax benefit (expense) | $ (5,797) | $ (59,440) | $ (29,930) |

The change in the Federal tax rate was due to the passage of Public Law No. 115-97, commonly referred to as the Jobs Act, which was enacted on December 22, 2017. The passage of this legislation resulted in the Company generating a deferred tax benefit primarily due to the reduction in the U.S. statutory rate from 35% to 21%.

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities are presented below:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| **Deferred tax assets:** | | |
| Net operating loss carryforwards | $ 88,043 | $ 87,196 |
| Capitalized intangible drilling cost | 100,307 | 29,159 |
| Interest expense | 18,722 | 6,023 |
| Equity-based compensation | 8,284 | 3,366 |
| Other assets | 295 | 282 |
| Total deferred tax assets | 215,651 | 126,026 |
| **Deferred tax liabilities:** | | |
| Investment in CRP | (301,155) | (188,193) |
| Net deferred tax asset (liability) | $ (85,504) | $ (62,167) |

In connection with the conversion of shares from a noncontrolling interest owner, a tax loss was recorded in equity of $17.5 million in 2019 and a tax benefit was recorded in equity of $7.2 million and $20.0 million, respectively, for 2018 and 2017.

As of December 31, 2019, the Company had approximately $417.4 million and $78.2 million of U.S. federal and state net operating loss carryovers, respectively, which expire variously from 2035 to 2038.

The Company periodically assesses whether it is more-likely-than-not that it will generate sufficient taxable income to realize its deferred income tax assets, including interest limitations and net operating loss carry forwards. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. Based on when the Company expects existing taxable differences to be realized, management determined that sufficient positive evidence exists as of December 31, 2019 to conclude that it is more-likely-than-not that the remaining deferred tax assets will be realized prior to their expiration.

The calculation of the Company’s tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon the examination by the Internal Revenue Service or other governmental agency. As of December 31, 2019 and 2018, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. Interest and penalties related to uncertain tax positions are reported in income tax expense.

The Company is subject to the following material taxing jurisdictions: U.S., Colorado, New Mexico, and Texas. As of December 31, 2019, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2016 through 2019.

## Note 12—Transactions with Related Parties

Riverstone and its affiliates beneficially own more than 10% equity interest in the Company and are therefore considered related parties. The Company obtains services related to its drilling and completion activities as well as gas marketing and processing from affiliates of Riverstone from time to time. The Company believes that the terms of these arrangements are no less favorable to either party than those held with unaffiliated parties. The following table summarizes the costs incurred and revenues recognized from such arrangements as presented in the Consolidated Statements of Operations for the periods indicated, as well as the related net receivables or payables outstanding as of the balance sheet dates:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2019** | **2018** | **2017** |
| Lucid Energy Delaware, LLC ("Lucid") | | | |
| Oil and gas sales | $ 3,559 | $ 3,946 | $ — |
| Gathering, processing and transportation expenses | 2,642 | 792 | — |
| Liberty Oilfield Services, LLC | | | |
| Cost of goods/services provided[(1)] | $ — | $ — | $ 72,551 |

[(1)] The costs incurred for such drilling and completion activities are either included in natural gas properties in the Consolidated Balance Sheet or as lease operating expense in the Consolidated Statements of Operations.

| **(in thousands)** | **December 31, 2019** | **December 31, 2018** |
|---|---|---|
| Accounts receivable, net[(1)] | $ 91 | $ 325 |

[(1)] The receivables relate to amounts due from Lucid and are presented net of unpaid processing fees incurred as of the indicated period end date.

## Note 13—Commitments and Contingencies

### *Contractual Obligations*

The following table is a schedule of the Company's future minimum payments with commitments that have initial or remaining non-cancelable contractual terms in excess of one year as of December 31, 2019**:**

| **(in thousands)** | **2020** | **2021** | **2022** | **2023** | **2024** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Water disposal agreements | $ 2,237 | $ 100 | $ — | $ — | $ — | $ — | $ 2,337 |
| Purchase obligations | 9,302 | 3,360 | — | — | — | — | 12,662 |
| Transportation agreements | 13,393 | 9,061 | 1,773 | — | — | — | 24,227 |
| Total | $ 24,932 | $ 12,521 | $ 1,773 | $ — | $ — | $ — | $ 39,226 |

### Water Disposal Agreement

The Company has entered into agreements for the transportation and disposal of produced water from a portion of its operated wells. Under the terms of these agreements, Centennial is obligated to provide a minimum volume of produced water or else pay for any deficiencies at the prices stipulated in the contract. The obligations reported above represent the minimum financial commitment pursuant to the terms of the contracts as of December 31, 2019. Actual expenditures under these contracts may exceed the minimum commitments presented above. The Company recognized water disposal costs of $2.6 million, $2.2 million and $2.4 million for the years ended December 31, 2019, 2018 and 2017, respectively, related to its water disposal agreements.

**Purchase Obligations**

The Company has purchase agreements to buy frac sand, which is used in its well fracture stimulation process. Under the terms of these agreements, Centennial is obligated to purchase a minimum volume of frac sand at a fixed sales price. The obligations included in the table above represent the minimum financial commitments pursuant to the terms of the contracts as of December 31, 2019. Actual expenditures under these contracts may exceed the minimum commitments presented above. Pursuant to the terms of one of the frac sand purchase agreements, the Company paid $13.2 million during the year ended December 31, 2017 as a pre-payment for advanced purchases of frac sand of which $5.2 million, $4.6 million and $1.6 million were capitalized as incurred in 2019, 2018 and 2017, respectively. Additionally, the Company paid $24.8 million and $9.7 million for the years ended December 31, 2019 and 2018, respectively, under these contracts, which was capitalized as incurred during the periods.

**Transportation and Gathering Agreements**

The Company has various natural gas transportation and gathering agreements whereby it is required to deliver specified quantities over the contractual term as summarized below or else pay any volume deficiencies. These delivery commitments are tied to the Company’s natural gas production; however, the Company is not required to deliver oil or gas specifically produced from any of the Company’s properties under these agreements. The obligations reported above represent the gross minimum financial commitments pursuant to the terms of these agreements as of December 31, 2019 but exclude potential financial obligations related to an agreement that has variable pricing components as the future obligation cannot be determined. Actual expenditures under these contracts may exceed the minimum commitment amounts presented above. The Company paid transportation and gathering costs of $12.8 million, $3.7 million and $1.2 million for the years ended December 31, 2019, 2018 and 2017, respectively, related to these agreements.

The following table summarizes the natural gas volumes the Company is required to deliver by period under these agreements:

| Period | Total Volume Commitments (MMBtu)[(1)] | Daily Volume Commitments (MMBtu/d)[(1)] |
|---|---|---|
| January 2020 - December 2020 | 114,111,400 | 311,800 |
| January 2021 - December 2021 | 101,269,000 | 277,400 |
| January 2022 - October 2022 | 19,700,000 | 64,800 |
| Total | 235,080,400 | |

(1) The amounts reflected within this table are the total gross volumes the Company is required to deliver per the agreements. These volumetric quantities are therefore not comparable to the Company’s net production presented in *Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operation* as the amounts therein are reflected net of all royalties, overriding royalties and production due to others.

***Delivery Commitments***

In August 2018, the Company entered into two firm crude oil sales agreements with large integrated oil companies. Utilizing these companies’ transport capacity out of the Permian Basin, the agreements provide for firm gross sales ranging from approximately 30,000 to 105,000 Bbls/d in aggregate over six years beginning in 2019. These sales agreements only require the Company to physically deliver 30,000 Bbls/d of the aforementioned volumes of crude oil during the contractual years 2020 through 2024, which if not met, would result in a financial obligation. Failure to deliver the remainder of the committed volumes of crude oil under these agreements could result in a reduction of future contractual volumes at the purchaser’s discretion in accordance with the terms of the agreements.

The Company has firm gas sales agreements that provide for firm gross sales ranging from approximately 40,000 to 100,000 MMBtu/d in aggregate over four years beginning 2019. These sales agreements do not require the Company to physically deliver the aforementioned volumes of natural gas over the contractual terms of the agreements. However, if the firm commitments are not met and the purchaser incurs financial damages, the Company may be required to pay for differences between the contracted prices and current market prices for replacement volumes bought by the purchaser and the purchaser may also require the Company to provide additional financial guaranty in accordance with the terms of the agreements.

The amounts discussed above represent the total gross volumes the Company is required to deliver per the agreements, which are not comparable to the Company's net production presented in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation* as amounts therein are reflected net of all royalties, overriding royalties and production due to others. The Company believes its current production and reserves are sufficient to fulfill the physical delivery commitments; however, the Company is not required to deliver oil or gas specifically produced from any of the Company's properties under these agreements. Further, if the Company's production is not sufficient to satisfy the firm delivery commitments, the Company believes it can purchase sufficient volumes in the market at index-related prices to satisfy its commitments. The aggregate amount of any such potential financial obligation under these contracts is not determinable since the amount and timing of any volumetric shortfalls, as well as the difference between the prevailing market price and contract price at such time, cannot be predicted with accuracy.

***Lease Commitments***

Refer to *Note 15—Leases* for details on the Company's operating lease agreements.

***Contingencies***

The Company may at times be subject to various commercial or regulatory claims, litigation or other legal proceedings that arise in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, management believes it is remote that the impact of such matters that are reasonably possible to occur will have a material adverse effect on the Company's financial position, results of operations or cash flows. Management is unaware of any pending litigation brought against the Company requiring the reserve of a contingent liability as of the date of these consolidated financial statements.

**Note 14—Revenues**

***Revenue from Contracts with Customers***

Crude oil, natural gas and NGL sales are recognized at the point control of the product is transferred to the customer and collectability is reasonably assured. Virtually all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, transportation costs to an active spot market and quality differentials. As a result, the Company's realized price of oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies both globally (in the case of crude oil) and locally.

Oil and gas revenues presented within the Consolidated Statements of Operations relate to the sale of oil, natural gas and NGLs as shown below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2019 | 2018 | 2017 |
| Operating revenues (in thousands): | | | |
| Oil sales | $ 810,655 | $ 709,813 | $ 336,931 |
| Natural gas sales | 44,556 | 62,325 | 48,868 |
| NGL sales | 89,119 | 118,907 | 44,103 |
| Oil and gas sales | $ 944,330 | $ 891,045 | $ 429,902 |

Oil sales

The Company's crude oil sales contracts are generally structured whereby oil is delivered to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes title of the product. This delivery point is usually at the wellhead or at the inlet of a transportation pipeline. Revenue is recognized when control transfers to the purchaser at the delivery point based on the net price received from the purchaser. Any downstream transportation costs incurred by crude purchasers are reflected as a net reduction to oil sales revenues.

*Natural gas and NGL sales*

Under the Company’s natural gas processing contracts, liquids rich natural gas is delivered to a midstream processing entity at the inlet of the gas plant processing system. The midstream processing entity gathers and processes the raw gas and then remits proceeds to Centennial for the resulting sales of NGLs, while the Company generally elects to take its residue gas product “in-kind” at the plant tailgate. For these contracts, the Company evaluates when control is transferred and revenue should be recognized. Where the Company has concluded that control transfers at the tailgate of the processing facility, fees incurred prior to transfer of control are presented as gathering, processing and transportation expenses (“GP&T”) within the Consolidated Statements of Operations. Any transportation and fractionation costs incurred subsequent to the point of transfer of control are reflected as a net reduction to natural gas and NGL sales revenues presented in the table above.

***Performance obligations***

For all commodity products, the Company records revenue in the month production is delivered to the purchaser. Settlement statements for natural gas and NGL sales may not be received for 30 to 90 days after the date production volumes are delivered and for crude oil, generally within 30 days after delivery has occurred. However, payment is unconditional once the performance obligations have been satisfied. At this time, the volume and price can be reasonably estimated and amounts due from customers are accrued in *Accounts receivable, net i*n the Consolidated Balance Sheets. As of December 31, 2019 and December 31, 2018, such receivable balances were $76.6 million and $67.0 million, respectively.

The Company records any differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Historically, any identified differences between revenue estimates and actual revenue received have not been significant. For the years ended December 31, 2019 and 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods were not material.

***Transaction price allocated to remaining performance obligations***

For the Company’s product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606 which states the Company is not required to disclose the transaction price allocated to the remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, monthly sales of a product generally represent a separate performance obligation; therefore, future commodity volumes to be delivered and sold are wholly unsatisfied and disclosure of the transaction price allocated to such unsatisfied performance obligations is not required.

**Note 15—Leases**

***Lease Commitments (ASC Topic 842)***

At contract inception, the Company determines whether or not an arrangement contains a lease. However, in connection with the implementation of ASC 842, this assessment was made as of the adoption date. Upon determination of a lease, a lease right-of-use (ROU) asset and related liability are recorded based on the present value of the future lease payments over the lease term. ROU assets represent the Company’s right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make future lease payments arising from the lease.

Currently, the Company has operating leases for drilling rig contracts, office rental agreements, and other wellhead equipment. As of December 31, 2019, these leases have remaining lease terms ranging from two months to two years, some of which include options to extend the lease term for up to five years, and some of which include options to early terminate. These options are considered in determining the lease term and are included in the present value of future payments that are recorded for leases when the Company is reasonably certain to exercise the option. Leases with an initial term of one year or less are not recorded in the Consolidated Balance Sheets. Additionally, none of the Company’s lease agreements contain any material residual value guarantees or material restrictive covenants.

The present value of future lease payments is determined at the lease commencement date based upon the Company's incremental borrowing rate. The incremental borrowing rate is calculated for each lease using a risk-free interest rate adjusted for the Company's specific risk and the specific lease term. The table below summarizes the Company's discount rate and remaining lease term as of the period presented.

| | As of December 31, 2019 |
|---|---|
| Weighted-average discount rate | 4.56% |
| Weighted-average remaining lease term (years) | 1.29 |

The Company's drilling rig contracts, office rental agreements, and wellhead equipment agreements contain both lease and non-lease components, which are combined and accounted for as a single lease component.

Variable lease payments are recognized in the period in which they are incurred and include operating expenses related to the office rental agreements and expenses incurred on the drilling rig contracts in excess of the contractual rate. Expenses related to short-term leases are recognized on a straight-line basis over the lease term. The following table presents the components of the Company's lease expenses for the period presented.

| (in thousands) | | Year Ended December 31, 2019 |
|---|---|---|
| Lease costs(1) | | |
| Operating lease cost | $ | 37,679 |
| Variable lease cost | | 3,566 |
| Short-term lease cost | | 67,493 |
| Total Lease Cost | $ | 108,738 |

(1) The majority of the Company's operating leases relate to the operations or completion of the Company's wells. Therefore, the lease costs presented in the above table represent the total gross costs the Company incurs, which are not comparable to the Company's net costs recorded to the Consolidated Statements of Operations, Consolidated Statements of Cash Flows or capitalized in the Consolidated Balance Sheets, as amounts therein are reflected net of amounts billed to working interest partners.

Maturities of the Company's long-term operating lease liabilities by for the year ended December 31, 2019 are as follows:

| (in thousands) | | Total(2) |
|---|---|---|
| 2020 | $ | 9,573 |
| 2021 | | 3,033 |
| 2022 | | 425 |
| Total lease payments | | 13,031 |
| Less: imputed interest | | (445) |
| Present value of lease liabilities (1) | $ | 12,586 |

(1) Of the total present value of lease liabilities, $9.2 million was recorded to current *Operating lease liabilities* and $3.4 million was recorded in noncurrent *Operating lease liabilities* in the Consolidated Balance Sheets as of December 31, 2019.

(2) Total lease payments exclude variable lease payments which can be charged under the terms of the lease agreements.

***Lease Commitments (ASC Topic 840)***

The following is a schedule of the Company's future contractual payments for operating leases under the scope of ASC 840 that had initial contractual terms greater than one year as of December 31, 2018**:**

| (in thousands) | | Drilling Rigs | | Office Leases |
|---|---|---|---|---|
| 2019 | $ | 43,036 | $ | 3,057 |
| 2020 | | 4,124 | | 2,830 |
| 2021 | | — | | 2,761 |
| 2022 | | — | | 404 |
| Total lease payments | $ | 47,160 | $ | 9,052 |

**Note 16—Subsequent events**

On February 24, 2020, the Company entered into a purchase and sale agreement to sell its water disposal assets for a base sale price of approximately $150 million in cash at closing with up to an additional $75 million in deferred incentive payments based on future drilling activity (all amounts are subject to post-closing adjustments). The water disposal assets include certain saltwater disposal wells and the associated water infrastructure located in Reeves and Ward counties in Texas. The closing of the sale is expected to occur at the end of the first quarter of 2020, and the Company does not expect this divestiture to result in a gain or loss on sale.

**Supplemental Information About Oil & Natural Gas Producing Activities (Unaudited)**

***Capitalized Costs***

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

| (in thousands) | December 31, 2019 | December 31, 2018 |
|---|---|---|
| Proved properties | $ 3,962,175 | $ 2,895,280 |
| Unproved properties | 1,470,903 | 1,680,065 |
| Total proved and unproved properties | 5,433,078 | 4,575,345 |
| Accumulated depreciation, depletion and amortization | (931,737) | (496,900) |
| Net capitalized costs | $ 4,501,341 | $ 4,078,445 |

***Costs Incurred for Oil and Natural Gas Producing Activities***

The costs incurred in the Company’s oil and gas production, exploration, and development activities are displayed in the table below and include costs whether capitalized or expensed as well as revisions and additions to the estimated future asset retirement obligations.

| | Year Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2019 | 2018 | 2017 |
| Acquisition costs: | | | |
| Proved properties | $ 3,437 | $ 39,731 | $ 54,550 |
| Unproved properties | 81,602 | 173,519 | 350,567 |
| Advances for unproved properties(1) | 18,345 | — | — |
| Development costs | 875,911 | 933,639 | 585,866 |
| Exploration costs | 11,390 | 9,968 | 21,542 |
| Total | $ 990,685 | $ 1,156,857 | $ 1,012,525 |

(1) Advances for unproved properties represent amounts paid to a third-party broker to acquire approximately 24,000 net leasehold acres on the Company’s behalf in the Permian Basin. Accordingly, these leasehold acres are not included in the Company’s total leasehold acreage disclosed in *Acreage*, Item 2. Business and Properties in this Annual Report. This prepaid amount is included in *Other noncurrent assets* line item on the Consolidated Balance Sheet as of December 31, 2019.

***Estimated Quantities of Proved Oil and Gas Reserves***

The reserve estimates presented below and included herein conform to the definitions prescribed by the SEC. The Company retained Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, to prepare the estimates of all of its proved reserves as of December 31, 2019, 2018 and 2017 and their related pre-tax future net cash flows. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. 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.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC.

As of December 31, 2019, all of the Company's oil and gas reserves are attributable to properties within the United States. The table below presents a summary of changes in quantities of proved oil and gas reserves in the Company's estimated proved reserves:

| | Crude Oil (MBbls) | Natural Gas (MMcf) | Natural Gas Liquids (MBbls) | Total (MBoe)[1] |
|---|---|---|---|---|
| **Total proved reserves:** | | | | |
| Balance - December 31, 2016 | 46,466 | 148,344 | 11,770 | 82,959 |
| Extensions and discoveries | 47,870 | 174,458 | 17,465 | 94,411 |
| Revisions to previous estimates | 10,751 | 16,154 | 3,114 | 16,556 |
| Purchases of reserves in place | 3,211 | 6,822 | 435 | 4,784 |
| Divestitures of reserves in place | (371) | (812) | (120) | (626) |
| Production | (6,994) | (17,754) | (1,678) | (11,630) |
| Balance - December 31, 2017 | 100,933 | 327,212 | 30,986 | 186,454 |
| Extensions and discoveries | 64,159 | 179,052 | 23,937 | 117,938 |
| Revisions to previous estimates | (12,429) | (74,781) | 770 | (24,123) |
| Purchases of reserves in place | 3,573 | 7,455 | 1,012 | 5,827 |
| Divestitures of reserves in place | (791) | (4,379) | (455) | (1,975) |
| Production | (12,679) | (31,707) | (4,332) | (22,295) |
| Balance - December 31, 2018 | 142,766 | 402,852 | 51,918 | 261,826 |
| Extensions and discoveries | 33,093 | 76,820 | 10,527 | 56,424 |
| Revisions to previous estimates | (9,845) | 64,558 | 10,047 | 10,959 |
| Purchases of reserves in place | 9 | 209 | 30 | 74 |
| Divestitures of reserves in place | (282) | (306) | (46) | (378) |
| Production | (15,582) | (41,703) | (5,234) | (27,766) |
| Balance - December 31, 2019 | 150,159 | 502,430 | 67,242 | 301,139 |
| | | | | |
| **Proved developed reserves:** | | | | |
| December 31, 2017 | 41,786 | 126,065 | 12,133 | 74,929 |
| December 31, 2018 | 63,317 | 180,542 | 23,093 | 116,500 |
| December 31, 2019 | 74,842 | 237,791 | 32,743 | 147,216 |
| | | | | |
| **Proved undeveloped reserves:** | | | | |
| December 31, 2017 | 59,147 | 201,147 | 18,853 | 111,525 |
| December 31, 2018 | 79,449 | 222,310 | 28,825 | 145,326 |
| December 31, 2019 | 75,317 | 264,639 | 34,499 | 153,923 |

[1] Calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe.

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- *Extensions and discoveries.* In 2019, 56.4 MMBoe of proved reserves were added through extensions and discoveries and include: i) 30.5 MMBoe for new PUD locations; and ii) 25.9 MMBoe for unproved locations that were successfully converted to new PDP wells during the period. These additions resulted from the Company's effective drilling program throughout the year, which added locations primarily in the Upper Wolfcamp A formation in the Company's Texas position and also in the 2nd Bone Spring formations in the Company's New Mexico acreage.

- *Revisions to previous estimates.* In 2019, revisions to previous estimates of 11.0 MMBoe consisted of 27.5 MMBoe of upward revisions primarily related to well performance revisions to reflect higher gas and NGL yields on older wells, which in turn increased total estimated ultimate recovery ("EURs") for most proved developed and PUD locations. These positive revisions were partially offset by 16.5 MMBoe of negative revisions, of which 10.1 MMBoe related to downward pricing adjustments due to lower average commodity prices for oil, gas and NGLs for the year ended December 31, 2019. The remainder of the downward revisions related to PUD locations that were reclassified to unproven reserves due to them no longer being a part of the Company's active development program.

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* In 2018, total extensions and discoveries of 117.9 MMBoe were primarily attributable to increased drilling activity as a result of the Company's seven-rig drilling program effective throughout the year. These additions include 90.0 MMBoe related to new PUD locations, primarily in the Upper Wolfcamp A, and 27.9 MMBoe for the conversion of unproved locations to PDP wells.

- *Revisions to previous estimates.* In 2018, revisions to previous estimates were 24.1 MMBoe and mainly consist of negative revisions to PUD locations of 20.3 MMBoe. Of these PUD revisions, the majority related to locations that were reclassified to unproven reserves due to them no longer being a part of the Company's active development program. In addition, 1.4 MMBoe of reserves were removed for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules.

- *Purchases of reserves in place.* In 2018, purchases of reserves of 5.8 MMBoe was primarily attributable to asset acquisitions discussed in *Note 2—Property Acquisitions and Divestitures*.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 94.4 MMBoe were primarily attributable to increased drilling activity as a result of the Company's six-rig drilling program effective throughout the year. These additions include 66.6 MMBoe related to new PUD locations and 27.8 MMBoe for the conversion of unproved locations to PDP wells primarily in the Upper Wolfcamp A zone.

- *Revisions to previous estimates.* In 2017, revisions to previous estimates of 16.6 MMBoe were composed of positive revisions of 26.4 MMBoe primarily relating to adjustments to PUD well locations scheduled to be drilled at longer lateral lengths as well as additional positive performance revisions attributable to more wells drilled with longer lateral lengths in 2017. These positive revisions were partially offset by 9.8 MMBoe of negative revisions associated with PUD reclassification to unproven reserves as they are no longer expected to be developed within the five years of their initial recording in accordance with SEC rules.

- *Purchases of reserves in place.* In 2017, purchases of reserves of 4.8 MMBoe was primarily attributable to the GMT Acquisition in June. Refer to *Note 2—Property Acquisitions and Divestitures* for further details.

***Standardized Measure of Discounted Future Net Cash Flows***

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves has been prepared in accordance with FASB ASC Topic 932, *Extractive Activities - Oil and Gas* (the "Standardized Measure"). Future cash inflows as of December 31, 2019, 2018 and 2017 have been computed by applying average fiscal year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month periods ended December 31, 2019, 2018 and 2017, respectively) 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 gas reserves, based on year-end costs and assuming the continuation of existing economic conditions. The Standardized Measure also includes costs for future dismantlement, abandonment and rehabilitation obligations.

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, less the tax basis of properties involved. 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. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

The following table presents the Company's Standardized Measure of discounted future net cash flows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2019** | **2018** | **2017** |
| Future cash inflows | $ 9,616,702 | $ 10,989,064 | $ 6,586,516 |
| Future development costs | (1,410,494) | (1,548,551) | (880,767) |
| Future production costs | (3,943,766) | (3,313,981) | (2,233,266) |
| Future income tax expenses | (391,168) | (1,027,976) | (542,587) |
| Future net cash flows | 3,871,274 | 5,098,556 | 2,929,896 |
| 10% discount to reflect timing of cash flows | (1,808,902) | (2,618,705) | (1,426,570) |
| Standardized measure of discounted future net cash flows | $ 2,062,372 | $ 2,479,851 | $ 1,503,326 |

The following summarizes the principal sources of change in the Standardized Measure of discounted future net cash flows and such changes have been computed in accordance with FASB ASC Topic 932, *Extractive Activities - Oil and Gas*:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2019** | **2018** | **2017** |
| Standardized measure of discounted future net cash flows, beginning of period | $ 2,479,851 | $ 1,503,326 | $ 375,092 |
| Sales of oil, natural gas and NGLs, net of production costs | (662,319) | (693,585) | (331,134) |
| Purchase of minerals in place | 154 | 61,137 | 56,658 |
| Divestiture of minerals in place | (5,593) | (17,516) | (4,607) |
| Extensions and discoveries, net of future development costs | 526,083 | 1,213,206 | 842,756 |
| Previously estimated development costs incurred during the period | 380,376 | 380,452 | 139,246 |
| Net change in prices and production costs | (1,395,537) | 532,702 | 281,026 |
| Change in estimated future development costs | 15,056 | (145,048) | (60,301) |
| Revisions of previous quantity estimates | 47,226 | (155,943) | 253,399 |
| Accretion of discount | 297,946 | 174,806 | 42,753 |
| Net change in income taxes | 364,089 | (254,873) | (156,574) |
| Net change in timing of production and other | 15,040 | (118,813) | 65,012 |
| Standardized measure of discounted future net cash flows, end of period | $ 2,062,372 | $ 2,479,851 | $ 1,503,326 |

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate weighted average sales prices (inclusive of adjustments for transportation, quality, and basis differentials) for each of the periods indicated below as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2019** | **2018** | **2017** |
| Oil (per Bbl) | $ 52.62 | $ 58.71 | $ 48.43 |
| Gas (per Mcf) | 0.87 | 2.45 | 2.74 |
| NGLs (per Bbl) | 18.99 | 31.20 | 25.92 |

**Selected Quarterly Financial Data (Unaudited)**

| | Quarter Ended | | | |
|---|---|---|---|---|
| (in thousands) | March 31 | June 30 | September 30 | December 31 |
| **2019** | | | | |
| Operating revenues | $ 214,569 | $ 244,239 | $ 229,130 | $ 256,392 |
| Operating expenses | 209,462 | 207,142 | 217,766 | 229,674 |
| Income from operations[1] | 5,105 | 37,106 | 11,342 | 25,876 |
| Other income (expense)[1] | (15,905) | (12,176) | (13,662) | (15,475) |
| Income tax (expense) benefit | 2,263 | (5,928) | (1,393) | (739) |
| Net income (loss) attributable to Class A Common Stock | (8,112) | 17,877 | (3,585) | 9,618 |
| Income (loss) per share of Class A Common Stock: | | | | |
| Basic | $ (0.03) | $ 0.07 | $ (0.01) | $ 0.03 |
| Diluted | (0.03) | 0.07 | (0.01) | 0.03 |

| | Quarter Ended | | | |
|---|---|---|---|---|
| (in thousands) | March 31 | June 30 | September 30 | December 31 |
| **2018** | | | | |
| Operating revenues | $ 215,898 | $ 217,763 | $ 234,880 | $ 222,504 |
| Operating expenses | 128,031 | 141,092 | 165,514 | 173,693 |
| Income from operations[1] | 87,882 | 76,530 | 69,418 | 49,360 |
| Other income (expense)[1] | 2,027 | 10,892 | (16,092) | (7,841) |
| Income tax expense | (19,137) | (19,940) | (11,652) | (8,711) |
| Net income attributable to Class A Common Stock | 66,090 | 63,541 | 39,288 | 30,980 |
| Income per share of Class A Common Stock: | | | | |
| Basic | $ 0.25 | $ 0.24 | $ 0.15 | $ 0.12 |
| Diluted | 0.25 | 0.24 | 0.15 | 0.12 |

[1] Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Control and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, the Company has evaluated, under the supervision and with the participation of management, including the principal executive officer and principal financial officer, the effectiveness of the design and operation of disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports that the Company files under the Exchange Act is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, the principal executive officer and principal financial officer concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2019 at the reasonable assurance level.

### Management’s Annual Report on Internal Control Over Financial Reporting

Management, including the principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. The Company’s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP.

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.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2019, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that the Company’s internal control over financial reporting was effective as of December 31, 2019.

This Annual Report includes an attestation report of KPMG LLP, the Company’s independent registered public accounting firm, on the Company’s internal control over financial reporting as of December 31, 2019, which is included in this Annual Report.

### Changes in Internal Control over Financial Reporting

There were no changes in the system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

## ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2020 annual meeting of stockholders and is incorporated herein by reference.

# PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS SCHEDULES



| Exhibit Number | Description of Exhibits |
|---|---|
| 2.1 | Contribution Agreement, dated as of July 6, 2016, as amended by Amendment No. 1 thereto, dated as of July 29, 2016, among Centennial Resource Development, LLC, NGP Centennial Follow-On LLC, Celero Energy Company, LP, Centennial Resource Production, LLC and New Centennial, LLC (incorporated by reference to Annex A of the Registrant's definitive proxy statement filed with the SEC on September 23, 2016). |
| 2.2 | Purchase and Sale Agreement, dated as of November 21, 2016, by and among SB RS Holdings, LLC, Silverback Exploration, LLC and Silverback Operating, LLC (incorporated by reference to Exhibit 2.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-215621) filed with the SEC on January 19, 2017). |
| 2.3 | Purchase and Sale Agreement, dated as of April 28, 2017, by and between GMT Exploration Company LLC and Centennial Resource Production, LLC (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 1, 2017). |
| 3.1 | Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019). |
| 3.2 | Second Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 1, 2019). |
| 3.3 | Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of October 11, 2016 (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 3.4 | Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of December 28, 2016 (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on December 29, 2016). |
| 3.5 | Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of March 20, 2017 (incorporated by reference to Exhibit 3.5 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 23, 2017). |
| 3.6 | Amendment No. 3 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of June 15, 2018 (incorporated by reference to Exhibit 3.6 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018). |
| 4.1 | Specimen Class A Common Stock Certificate (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016). |
| 4.2 | Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016). |
| 4.3 | Warrant Agreement between Continental Stock Transfer & Trust Company and the Registrant (incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed with the SEC on February 29, 2016). |
| 4.4 | Certificate of Designation of Series A Preferred Stock (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 4.5* | Description of Registrant's Common Stock |
| 4.6 | Indenture, dated as of November 30, 2017, by and among Centennial Resource Production, LLC, the subsidiary guarantors named therein and UMB Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed with the SEC on December 5, 2017). |
| 4.7 | Indenture, dated as of March 15, 2019, by and amount Centennial Resource Production, LLC, the subsidiary guarantors named therein and UMB Bank, N.A. as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed with SEC on March 18, 2019). |
| 10.1 | Amended and Restated Registration Rights Agreement among the Registrant and certain stockholders (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |

| | |
|---|---|
| 10.2 | Form of Indemnity Agreement (incorporated by reference to Exhibit 10.7 to the Registrant's Registration Statement on Form S-1 (Registration No. 333-209140) filed with the SEC on January 27, 2016). |
| 10.3 | Second Amended and Restated Credit Agreement, dated as of May 4, 2018, among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on May 8, 2018). |
| 10.4 | Purchase and Sale Agreement, dated as of August 2, 2018, by and between Centennial Resource Production, LLC and BP Products North America Inc. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on August 6, 2018). |
| 10.5 | Crude Oil Purchase and Sale Agreement, dated as of August 31, 2018, by and between Centennial Resource Production, LLC and ExxonMobil Oil Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed with the SEC on September 4, 2018). |
| 10.6# | Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 10.7# | Form of Stock Option Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 10.8# | Form of Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 10.9# | Form of Restricted Stock Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed with the SEC on October 11, 2016). |
| 10.10# | Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.16 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 26, 2018). |
| 10.11# | Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018). |
| 10.12# | Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 5, 2019). |
| 10.13# | Centennial Resource Development, Inc. Amended and Restated Severance Plan (incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on November 4, 2019). |
| 10.14# | Centennial Resource Development, Inc. Second Amended and Restated Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on August 5, 2019). |
| 10.15# | Centennial Resource Development, Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019). |
| 21.1 | Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 to the Registration Statement on Form S-1 of Centennial Resource Development, Inc. (Registration No. 333-214355) filed with the SEC on October 31, 2016). |
| 23.1* | Consent of KPMG LLP. |
| 23.2* | Consent of Netherland, Sewell & Associates, Inc. |
| 31.1* | Certification of the Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a). |
| 31.2* | Certification of the Chief Financial Officer required by Rule 13a-14(a) or Rule 15d-14(a). |
| 32.1* | Certification of the Chief Executive Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350. |
| 32.2* | Certification of the Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and 18 U.S.C. 1350. |
| 99.1 | Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2017 (incorporated by reference to Exhibit 99.3 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 26, 2018). |
| 99.2 | Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2018 (incorporated by reference to Exhibit 99.3 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 25, 2019). |
| 99.3* | Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2019. |
| 101.INS* | Inline XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. |
| 101.SCH* | Inline XBRL Taxonomy Extension Schema Document. |
| 101.CAL* | Inline XBRL Taxonomy Extension Calculation Linkbase Document. |
| 101.DEF* | Inline XBRL Taxonomy Extension Definition Linkbase Document. |
| 101.LAB* | Inline XBRL Taxonomy Extension Label Linkbase Document. |
| 101.PRE* | Inline XBRL Taxonomy Extension Presentation Linkbase Document. |

* Filed herewith.

# Management contract or compensatory plan or agreement.

**ITEM 16. FORM 10-K SUMMARY**

None.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS
George S. Glyphis
*Vice President, Chief Financial Officer and Assistant Secretary*

Pursuant to the requirements of the Securities Act of 1934, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ MARK G. PAPA<br>Mark G. Papa | Chairman and Chief Executive Officer (Principal Executive Officer) | February 24, 2020 |
| /s/ GEORGE S. GLYPHIS<br>George S. Glyphis | Vice President, Chief Financial Officer and Assistant Secretary (Principal Financial Officer) | February 24, 2020 |
| /s/ BRENT P. JENSEN<br>Brent P. Jensen | Vice President and Chief Accounting Officer (Principal Accounting Officer) | February 24, 2020 |
| /s/ MAIRE A. BALDWIN<br>Maire A. Baldwin | Director | February 24, 2020 |
| /s/ KARL E. BANDTEL<br>Karl E. Bandtel | Director | February 24, 2020 |
| /s/ MATTHEW G. HYDE<br>Matthew G. Hyde | Director | February 24, 2020 |
| /s/ PIERRE F. LAPEYRE, JR.<br>Pierre F. Lapeyre, Jr. | Director | February 24, 2020 |
| /s/ DAVID M. LEUSCHEN<br>David M. Leuschen | Director | February 24, 2020 |
| /s/ JEFFREY H. TEPPER<br>Jeffrey H. Tepper | Director | February 24, 2020 |
| /s/ ROBERT M. TICHIO<br>Robert M. Tichio | Director | February 24, 2020 |
| /s/ STEVEN J. SHAPIRO<br>Steven J. Shapiro | Director | February 24, 2020 |

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

The following description of our Common Stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Third Amended and Restated Articles of Incorporation (the "**Articles of Incorporation**") and our Second Amended and Restated Bylaws (the "**Bylaws**"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.1 is a part. We encourage you to read our Articles of Incorporation and our for additional information.

## Authorized Capital Shares

Our authorized capital consist of 600,000,000 shares of Class A common stock with a par value of $0.0001 ("**Class A Common Stock**"), 20,000,000 shares of Class C common stock with a par value of $0.0001 per share ("**Class C Common Stock**") and 1,000,000 shares of preferred stock with a par value of $0.0001 per share ("**Preferred Stock**"). The outstanding shares of our Class A Common Stock are fully paid and nonassessable.

## Voting Rights

Subject to the rights of holders of outstanding shares of Preferred Stock, the holders of Class A Common Stock and Class C Common Stock are entitled to one vote per share on all matters voted on by the stockholders, including the election of directors. Our Class A Common Stock and Class C Common Stock do not have cumulative voting rights.

## Dividend Rights

Subject to the rights of holders of outstanding shares of Preferred Stock, if any, the holders of Class A Common Stock are entitled to receive dividends, if any, as may be declared from time to time by the Board of Directors in its discretion out of funds legally available for the payment of dividends.

## Liquidation Rights

Subject to any preferential rights of outstanding shares of Preferred Stock, holders of the Class A Common Stock will share ratably in all assets legally available for distribution to our stockholders in the event of dissolution.

## Other Rights and Preferences

Our Class A Common Stock has no sinking fund or redemption provisions or preemptive, conversion or exchange rights. Holders of Class A Common Stock may not act by unanimous written consent.

## Listing

The Common Stock is traded on The Nasdaq Stock Market LLC under the trading symbol "CDEV."

**EXHIBIT 23.1**

# Consent of Independent Registered Public Accounting Firm

The Board of Directors
Centennial Resource Development, Inc.

We consent to the incorporation by reference in the registration statement (Nos. 333-215119 and 333-231514) on Form S-8 and registration statements (Nos. 333-215621, 333-214355, 333-219738 and 333-219739) on Form S-3 of Centennial Resource Development, Inc. and subsidiaries (the Company) of our reports dated February 24, 2020, with respect to the consolidated balance sheets of Centennial Resource Development, Inc. and subsidiaries as of December 31, 2019 and 2018, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements) and the effectiveness of internal control over financial reporting as of December 31, 2019, which reports appear in the December 31, 2019 annual report on Form 10-K of Centennial Resource Development, Inc.

Our report refers to a change in the method of accounting for leases in 2019 due to the adoption of Accounting Standards Update 2016-02 Leases (ASC Topic 842).

/s/ KPMG LLP

Denver, Colorado
February 24, 2020

NETHERLAND, SEWELL & ASSOCIATES, INC.

## CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the inclusion of our exhibit letter dated January 29, 2020, in the Annual Report on Form 10-K of Centennial Resource Development, Inc. (the "Company") for the year ended December 31, 2019. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and of our exhibit letter dated January 29, 2020, into the registration statements (Nos. 333 215119 and 333-231514) on Form S-8 and registration statements (Nos. 333-215621, 333-214355, 333-219738, and 333-219739) on Form S-3 of the Company, including any amendments thereto, in accordance with the requirements of the Securities Act of 1933, as amended.

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 24, 2020

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

**EXHIBIT 31.1**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULES 13a-14(a) AND 15d-14(a)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Mark G. Papa, certify that:

1. I have reviewed this Annual Report on Form 10-K (this “report”) of Centennial Resource Development, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth 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 24, 2020

By: /s/ MARK G. PAPA

Mark G. Papa
Chief Executive Officer
(Principal Executive Officer)

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**
**PURSUANT TO RULES 13a-14(a) AND 15d-14(a)**
**OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, George S. Glyphis, certify that:

1. I have reviewed this Annual Report on Form 10-K (this “report”) of Centennial Resource Development, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth 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 24, 2020

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis
Vice President, Chief Financial Officer and Assistant Secretary
(Principal Financial Officer)

**EXHIBIT 32.1**

**CERTIFICATION 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 on Form 10-K for the year ended December 31, 2019 of Centennial Resource Development, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark G. Papa, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; 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 24, 2020

By: /s/ MARK G. PAPA

Mark G. Papa
Chief Executive Officer
(Principal Executive Officer)

**EXHIBIT 32.2**

**CERTIFICATION 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 on Form 10-K for the year ended December 31, 2019 of Centennial Resource Development, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, George S. Glyphis, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; 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 24, 2020

By: /s/ GEORGE S. GLYPHIS

George S. Glyphis

Vice President, Chief Financial Officer and Assistant Secretary (Principal Financial Officer)

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG • P. SCOTT FROST
JOHN G. HATTNER • MIKE K. NORTON
DAN PAUL SMITH • JOSEPH J. SPELLMAN
RICHARD B. TALLEY, JR. • DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

January 29, 2020

Mr. Jeff B. Thompson
Centennial Resource Development, Inc.
1001 17th Street, Suite 1800
Denver, Colorado 80202

Dear Mr. Thompson:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the Centennial Resource Production, LLC (CRP) interest in certain oil and gas properties located in New Mexico and Texas. CRP is a subsidiary of Centennial Resource Development, Inc. (CRD). 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 CRP. 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 CRD'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 CRP 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 | 74,841.8 | 32,742.7 | 237,790.6 | 2,590,487.2 | 1,574,349.2 |
| Proved Undeveloped | 75,316.8 | 34,499.5 | 264,639.2 | 1,671,954.3 | 623,541.7 |
| Total Proved | 150,158.7 | 67,242.2 | 502,429.7 | 4,262,441.4 | 2,197,890.9 |

*Totals may not add because of rounding.*

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. There are no proved developed non-producing reserves at the price and cost parameters used in this report. 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 CRP's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for CRP'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 posted price of $52.19 per barrel is adjusted for quality, transportation fees, and market differentials; the market differentials have been adjusted for existing contractual agreements. For gas volumes, the average Henry Hub spot price of $2.578 per MMBTU is adjusted for energy content, transportation fees, and market 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 $52.62 per barrel of oil, $18.99 per barrel of NGL, and $0.872 per MCF of gas.

Operating costs used in this report are based on operating expense records of CRP. 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. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of CRP are included to the extent that they are covered under joint operating agreements for the operated properties. The fees associated with CRP's transportation contracts are included as additional operating expenses. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by CRP 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 CRP'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 CRP 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 CRP receiving its net revenue interest share of estimated future gross production.

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 CRP, 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 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 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 CRP, 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. Neil H. Little, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 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.

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/ Neil H. Little | By: /s/ Mike K. Norton |
| Neil H. Little, P.E. 117966 | Mike K. Norton, P.G. 441 |
| Vice President | Senior Vice President |
| Date Signed: January 29, 2020 | Date Signed: January 29, 2020 |

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## 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
(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.

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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
(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.*

(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.

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

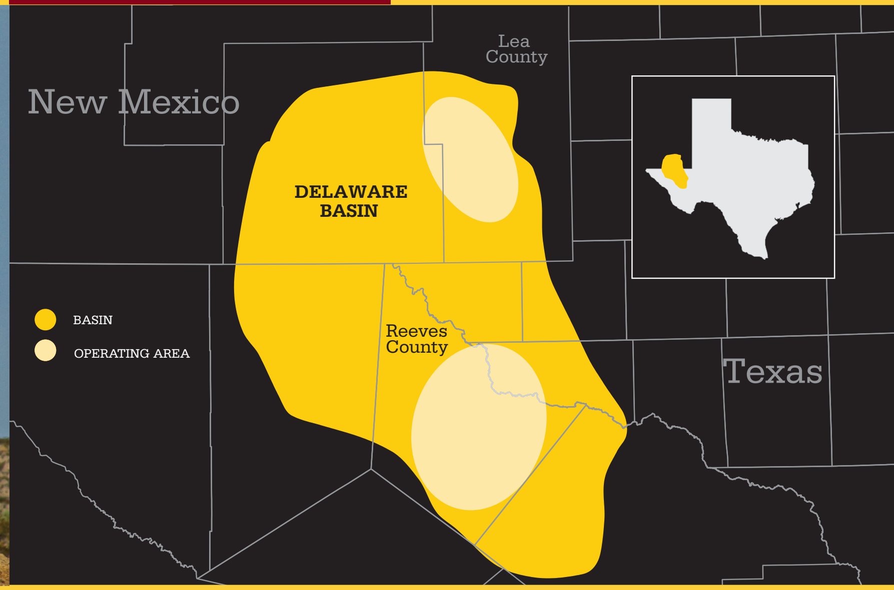
(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii)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

## AREAS OF OPERATION




## DIRECTORS AND OFFICERS

### Directors

**Mark G. Papa**
Chief Executive Officer and
Chairman of the Board

**Maire A. Baldwin** #+*
Lead Independent Director
Compensation Committee Chairperson

**Karl E. Bandtel** #*
Nominating and Corporate
Governance Committee Chairperson

**Matthew G. Hyde** +*

**Pierre F. Lapeyre, Jr.**

**David M. Leuschen**

**Steven J. Shapiro** #+

**Jeffrey H. Tepper** #+
Audit Committee Chairperson

**Robert M. Tichio**

# Audit Committee Member
+ Compensation Committee Member
* Nominating and Corporate Governance Committee Member

### Executive Officers

**Mark G. Papa**
Chief Executive Officer
and Chairman of the Board

**Sean R. Smith**
Vice President and Chief
Operating Officer

**George S. Glyphis**
Vice President and Chief
Financial Officer

**Brent P. Jensen**
Vice President and Chief
Accounting Officer

**Davis O. O'Connor**
Vice President and
General Counsel

### Other Officers

**Matt R. Garrison**
Vice President of Geosciences

**Sean W. Marshall**
Vice President of Land

**Kathleen M. Phillips**
Vice President of Human Resources

**Colleen C. Proctor**
Vice President of Information
Technology

**Clayton T. Smith**
Vice President of Operations

**Jeff B. Thompson**
Vice President of Reservoir Engineering

**William A. Weidig**
Vice President of Finance and Treasurer

### Company Information

**Annual Meeting**
The Annual Meeting will be held at
10:00 am Central Time
on April 29, 2020, at the Houston
Marriott Sugar Land located at:
16090 City Walk
Sugar Land, Texas 77479

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KPMG LLP

**Registrar and Stock Transfer Agent**
Continental Stock Transfer &
Trust Company

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**Ticker**
CDEV

**Stock Exchange Listing**
NASDAQ Stock Market

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