CONTINENTAL RESOURCES, INC
Form 10-K
February 19, 2019

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Oklahoma	73-0767549
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
20 N. Broadway, Oklahoma City, Oklahoma	73102
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (405) 234-9000
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨
		Emerging growth company	¨

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2018 was approximately $5.6 billion, based upon the closing price of $64.76 per share as reported by the New York Stock Exchange on such date.

376,014,925 shares of our $0.01 par value common stock were outstanding on January 31, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Shareholders to be held in May 2019, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

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Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:

"basin" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

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

"Bcf" One billion cubic feet of natural gas.

"Boe" Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

"Btu" British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

"completion" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

"conventional play" An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"DD&A" Depreciation, depletion, amortization and accretion.

"de-risked" Refers to acreage and locations in which the Company believes the geological risks and uncertainties related to recovery of crude oil and natural gas have been reduced as a result of drilling operations to date. However, only a portion of such acreage and locations have been assigned proved undeveloped reserves and ultimate recovery of hydrocarbons from such acreage and locations remains subject to all risks of recovery applicable to other acreage.

"developed acreage" The number of acres allocated or assignable to productive wells or wells capable of production.

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

"dry hole" Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

"enhanced recovery" The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.

"exploratory well" A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

"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.

"formation" A layer of rock which has distinct characteristics that differs from nearby rock.

"fracture stimulation" A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production. Also may be referred to as hydraulic fracturing.

"gross acres" or "gross wells" Refers to the total acres or wells in which a working interest is owned.

"held by production" or "HBP" Refers to an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

"horizontal drilling" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

"MBbl" One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe" One thousand Boe.

"Mcf" One thousand cubic feet of natural gas.

"MMBo" One million barrels of crude oil.
"MMBoe" One million Boe.
"MMBtu" One million British thermal units.
"MMcf" One million cubic feet of natural gas.
"net acres" or "net wells" Refers to the sum of the fractional working interests owned in gross acres or gross wells.
"Net crude oil and natural gas sales" Represents total crude oil and natural gas sales less total transportation expenses. Net crude oil and natural gas sales is a non-GAAP measure for 2018. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of such measure.
"Net sales price" Represents the average net wellhead sales price received by the Company for its crude oil or natural gas sales after deducting transportation expenses. Such amount is calculated by taking revenues less transportation expenses divided by sales volumes for a period, whether for crude oil or natural gas, as applicable. Net sales prices are non-GAAP measures for 2018. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of such measures.
"NYMEX" The New York Mercantile Exchange.
"pad drilling" or "pad development" Describes a well site layout which allows for drilling multiple wells from a single pad resulting in less environmental impact and lower per-well drilling and completion costs.
"play" A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.
"productive well" A well found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
"prospect" A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.
"proved reserves" The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.
"proved developed reserves" Reserves expected to be recovered through existing wells with existing equipment and operating methods.
"proved undeveloped reserves" or "PUD" Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion.
"PV-10" When used with respect to crude oil and natural gas reserves, PV-10 represents the estimated future gross revenues to be generated from the production of proved reserves using a 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December, net of estimated production and future development and abandonment costs based on costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission ("SEC"). PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company's crude oil and natural gas properties. The Company and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.
"reservoir" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
"residue gas" Refers to gas that has been processed to remove natural gas liquids.

“resource play” Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.
“royalty interest” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.
“SCOOP” Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.
“STACK” Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma.
“spacing” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.
“Standardized Measure” Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax net cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis in the crude oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.
“three dimensional (3D) seismic” Seismic surveys using an instrument to send sound waves into the earth and collect data to help geophysicists define the underground configurations. 3D seismic provides three-dimensional pictures. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We also use 3D seismic to identify sub-surface hazards to assist in steering, avoiding hazards and determining where to perform optimized completions.
“unconventional play” An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These areas tend to have low permeability and may be closely associated with source rock, as is the case with oil and gas shale, tight oil and gas sands and coalbed methane, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays.
“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.
“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
“well bore” The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well. Also called a well or borehole.
“working interest” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Cautionary Statement for the Purpose of the “Safe Harbor” Provisions of the Private Securities Litigation Reform Act of 1995

This report and information incorporated by reference in this report include “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company’s business and statements or information concerning the Company’s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, included in this report are forward-looking statements. The words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget,” “plan,” “continue,” “potential,” “guidance,” “strate expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include, but are not limited to, statements about:

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- future crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- competition;
- marketing of crude oil and natural gas;
- transportation of crude oil, natural gas liquids, and natural gas to markets;
- property exploitation, property acquisitions and dispositions, or joint development opportunities;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position;
- general economic conditions;
- credit markets;
- our liquidity and access to capital;
- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;
- our future operating and financial results;
- our future commodity or other hedging arrangements; and
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us.

Forward-looking statements are based on the Company’s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company’s control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate or will not change over time. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors and elsewhere in this report, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Part I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report. Unless the context otherwise requires, references in this report to “Continental Resources,” “Continental,” “we,” “us,” “our,” “ours” or “the Company” refer to Continental Resources, Inc. and its subsidiaries.

Item 1. Business

General

We are an independent crude oil and natural gas company formed in 1967 engaged in the exploration, development, and production of crude oil and natural gas primarily in the North, South and East regions of the United States. Additionally, we pursue the acquisition and management of perpetually owned minerals located in certain of our key operating areas. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

A substantial portion of our operations is located in the North region, with that region comprising 59% of our crude oil and natural gas production and 73% of our crude oil and natural gas revenues for the year ended December 31, 2018. The Company’s principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. Approximately 55% of our proved reserves as of December 31, 2018 are located in the North region. Our operations in the South region continue to expand with our increased activity in the SCOOP and STACK plays and that region comprised 41% of our crude oil and natural gas production, 27% of our crude oil and natural gas revenues, and 45% of our proved reserves as of and for the year ended December 31, 2018.

We focus our exploration activities in large new or developing crude oil and natural gas plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where three dimensional seismic, horizontal drilling, geosteering technologies, advanced completion technologies (e.g., fracture stimulation), pad/row development, and enhanced recovery technologies allow us to develop and produce crude oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drill bit.

As of December 31, 2018, our proved reserves were 1,522 MMBoe, with proved developed reserves representing 675 MMBoe, or 44%, of our total proved reserves. The standardized measure of our discounted future net cash flows totaled $15.7 billion at December 31, 2018. For 2018, we generated crude oil and natural gas revenues of $4.68 billion and operating cash flows of $3.46 billion. Crude oil accounted for 56% of our total production and 81% of our crude oil and natural gas revenues for 2018. Our total production averaged 298,190 Boe per day for 2018, a 23% increase compared to 2017.

The table below summarizes our total proved reserves, PV-10 (non-GAAP) and net producing wells as of December 31, 2018, average daily production for the quarter ended December 31, 2018 and the reserve-to-production index in our principal operating areas. The PV-10 values shown below are not intended to represent the fair market value of our crude oil and natural gas properties. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. See Part I, Item 1A. Risk Factors and “Critical Accounting Policies and Estimates” in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of this report for further discussion of uncertainties inherent in the reserve estimates.

	December 31, 2018				Average daily production for fourth quarter 2018 (Boe per day)		
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells		Percent of total	Annualized reserve/production index (2)
North Region:							
Bakken field							
North Dakota Bakken	767,837	50.4 %	$ 11,374	1,446	177,358	54.7 %	11.9
Montana Bakken	30,168	2.0 %	473	263	6,478	2.0 %	12.8
Red River units							
Cedar Hills	28,771	1.9 %	455	129	6,598	2.0 %	11.9
Other Red River units	3,661	0.2 %	55	114	2,446	0.8 %	4.1
Other	31	— %	1	2	33	— %	2.6
South Region:							
SCOOP	459,103	30.2 %	4,742	310	67,244	20.8 %	18.7
STACK	230,175	15.1 %	1,528	205	62,947	19.4 %	10.0
Other	2,619	0.2 %	22	120	897	0.3 %	8.0
Total	1,522,365	100.0%	$ 18,650	2,589	324,001	100.0%	12.9

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $3.0 billion. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for further discussion.

(2) The Annualized Reserve/Production Index is the number of years that estimated proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2018 production into estimated proved reserve volumes as of December 31, 2018.

Business Environment and Outlook

Our industry is impacted by volatility and uncertainty in commodity prices. Crude oil prices showed significant signs of improvement throughout the majority of 2018, with West Texas Intermediate crude oil benchmark prices rising above $75 per barrel in June and again in October before decreasing more than 40% in the fourth quarter to an 18-month low of $44 per barrel at year-end 2018. Crude oil prices have since rebounded from year-end 2018 lows, but remain volatile and unpredictable. Our leadership team has significant experience with operating in challenging commodity price environments. With our portfolio of high quality assets, we are well-positioned to manage the ongoing challenges and price volatility facing our industry.

For 2019, our primary business strategies will focus on:

- Enhancing free cash flow generation and oil-weighted production growth;
- Enhancing rates of return on capital employed through improvements in operating efficiencies, technical innovations, pad and row development, optimized completion methods, well productivity, and strategic mineral ownership;
- Continuing to exercise disciplined capital spending to maintain financial flexibility and ample liquidity; and
- Reducing outstanding debt using available operating cash flows, proceeds from asset dispositions, or joint development arrangements.

Our capital expenditures budget for 2019 is $2.6 billion compared to $2.8 billion spent in 2018, with the majority of our 2019 drilling and completion budget focusing on oil-weighted areas in North Dakota Bakken and SCOOP. Under the current commodity price environment, our planned capital expenditures for 2019 are expected to be funded entirely from operating cash flows. As we have done in the past, we may adjust our pace of drilling and development as 2019 market conditions evolve.

For 2019, we plan to operate an average of 25 drilling rigs and 9 completion crews for the year. We expect to spend approximately 41% of our 2019 capital expenditures budget on drilling and completion activities in the Bakken and 42% on drilling and completion activities in Oklahoma. The remaining 17% of our 2019 budget will target other capital expenditures such as leasing and renewals, mineral acquisitions, work-overs, and facilities. See the section below titled Summary of Crude Oil and Natural Gas Properties and Projects for further discussion of our 2019 plans.

Our Business Strategy

Despite volatility and uncertainty in commodity prices, our business strategy continues to be focused on increasing shareholder value by finding and developing crude oil and natural gas reserves at costs that provide attractive rates of return. The principal elements of this strategy include:

Growing and sustaining a premier portfolio of assets focused on free cash flow generation and oil-weighted production growth. We hold a portfolio of leasehold acreage, perpetually owned minerals, drilling opportunities, and uncompleted wells in certain premier U.S. resource plays with varying access to crude oil, natural gas, and natural gas liquids. We pursue opportunities to develop our existing properties as well as explore for new resource plays where significant reserves may be economically developed. Our capital programs are designed to allocate investments to projects that provide opportunities to deliver strong oil-weighted production growth while generating cash flows in excess of operating and capital requirements, to harvest our inventory of uncompleted wells, to convert our undeveloped acreage to acreage held by production, and to improve hydrocarbon recoveries and rates of return on capital employed. While our operations have historically focused on the exploration and development of crude oil, we also allocate significant capital to natural gas areas that provide attractive rates of return.

Enhance rates of return on capital employed through operating efficiencies, technical innovations, pad and row development, optimized completions, well productivity, and strategic mineral ownership. We continue to manage our business in the volatile commodity price environment by focusing on improving operating efficiencies and managing costs by exploiting technical innovations, pad and row development opportunities, and other means. Our key operating areas are characterized by large acreage positions in select unconventional resource plays with multiple stacked geologic formations that provide repeatable drilling opportunities and resource potential. We operate a significant portion of our wells and leasehold acreage and believe the concentration of our operated assets allows us to leverage our technical expertise and manage the development of our properties to enhance operating efficiencies and economies of scale.

Additionally, we capitalize on our geologic knowledge and land expertise to strategically acquire minerals in areas of future growth, thereby allowing us to enhance cash flows and project economics through the alignment of mineral ownership with our drilling schedule. Our mineral ownership strategy serves as another avenue to enhance shareholder returns.

Maintaining financial flexibility and a strong balance sheet. Maintaining a strong balance sheet, ample liquidity, and financial flexibility are key components of our business strategy. In 2018, we reduced our total debt by $585 million, or 9%, and had no outstanding borrowings on our credit facility at December 31, 2018. Additionally, we increased our cash on hand by $239 million during the year to $283 million at year-end 2018. We are actively targeting further debt reduction using available cash, operating cash flows, or proceeds from potential sales of non-strategic assets and joint development opportunities and will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry.

Focusing on organic growth through disciplined capital investments. Although we consider various growth opportunities, including property acquisitions, our primary focus is on organic growth through leasing and drilling in our core areas where we can exploit our extensive inventory of repeatable drilling opportunities to achieve attractive rates of return.

Our Business Strengths

We have a number of strengths we believe will help us successfully execute our business strategy, including the following:

Large acreage inventory. We held approximately 525,700 net undeveloped acres and 1.22 million net developed acres under lease as of December 31, 2018 concentrated in certain premier U.S. resource plays. We are among the largest leaseholders in the Bakken, SCOOP and STACK plays. Being an early entrant in these plays has allowed us to capture significant acreage positions in core parts of the plays.

Expertise with pad and row development, horizontal drilling, and optimized completion methods. We have substantial experience with horizontal drilling and optimized completion methods and continue to be among industry leaders in the use of new drilling and completion technologies. We continue to improve drilling and completion efficiencies through the use of multi-well pad and row development strategies. Further, we are among industry leaders in drilling long lateral lengths. We have also been among industry leaders in testing and utilizing optimized completion technologies involving various combinations of fluid types, proppant types and volumes, and stimulation stage spacing to determine optimal methods for improving recoveries and rates of return. We continually refine our drilling and completion techniques in an effort to deliver improved results across our properties.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2018, we operated properties comprising 85% of our total proved reserves. By controlling a significant portion of our operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and completion methods used.
Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry and with operating in challenging commodity price environments. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our 9 executive officers have an average of 39 years of oil and gas industry experience.
Financial Position and Liquidity. We have a credit facility with lender commitments totaling $1.5 billion that matures in April 2023. We had no outstanding borrowings on the facility at December 31, 2018 and continued to have no borrowings as of January 31, 2019. Our credit facility is unsecured and does not have a borrowing base requirement that is subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants.

Crude Oil and Natural Gas Operations

Proved Reserves

Proved reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. In connection with the estimation of proved reserves, the term “reasonable certainty” implies a high degree of confidence that the quantities of crude oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reserve engineers and Ryder Scott Company, L.P (“Ryder Scott”), our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps including isopach and structure maps, analogy and statistical analysis, and available downhole, production, seismic, and well test data.

The table below sets forth estimated proved crude oil and natural gas reserves information by reserve category as of December 31, 2018. Proved reserves attributable to noncontrolling interests are immaterial and are not separately presented herein. The standardized measure of our discounted future net cash flows totaled approximately $15.7 billion at December 31, 2018. Our reserve estimates as of December 31, 2018 are based primarily on a reserve report prepared by Ryder Scott. In preparing its report, Ryder Scott evaluated properties representing approximately 98% of our PV-10 and 98% of our total proved reserves as of December 31, 2018. Our internal technical staff evaluated the remaining properties. A copy of Ryder Scott’s summary report is included as an exhibit to this Annual Report on Form 10-K.

Our estimated proved reserves and related future net revenues, Standardized Measure and PV-10 at December 31, 2018 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2018 through December 2018, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $65.56 per Bbl for crude oil and $3.10 per MMBtu for natural gas ($61.20 per Bbl for crude oil and $3.22 per Mcf for natural gas adjusted for location and quality differentials).

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	346,969	1,955,727	672,923	$10,248.0
Proved developed non-producing	856	8,562	2,283	23.8
Proved undeveloped	409,271	2,627,325	847,159	8,378.5
Total proved reserves	757,096	4,591,614	1,522,365	$18,650.3
Standardized Measure (1)				$15,684.8

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $3.0 billion. See Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for further discussion.

The following table provides additional information regarding our estimated proved crude oil and natural gas reserves by region as of December 31, 2018.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North Region:						
Bakken field						
North Dakota Bakken	237,195	588,212	335,232	300,126	794,883	432,606
Montana Bakken	20,523	40,874	27,336	2,312	3,119	2,832
Red River units						
Cedar Hills	28,004	4,606	28,771	—	—	—
Other Red River units	3,659	13	3,661	—	—	—
Other	30	7	31	—	—	—
South Region:						
SCOOP	45,517	785,293	176,399	89,978	1,156,355	282,705
STACK	11,932	535,356	101,158	16,855	672,968	129,016
Other	965	9,928	2,618	—	—	—
Total	347,825	1,964,289	675,206	409,271	2,627,325	847,159

The following table provides information regarding changes in total estimated proved reserves for the periods presented.

	Year Ended December 31,		
MBoe	2018	2017	2016
Proved reserves at beginning of year	1,330,995	1,274,864	1,225,811
Revisions of previous estimates	(269,253)	(82,012)	(110,474)
Extensions, discoveries and other additions	565,030	240,206	249,430
Production	(108,839)	(88,562)	(79,390)
Sales of minerals in place	(8,011)	(15,197)	(10,513)
Purchases of minerals in place	12,443	1,696	—
Proved reserves at end of year	1,522,365	1,330,995	1,274,864

Revisions of previous estimates. Revisions for 2018 are comprised of (i) the removal of 74 MMBo and 960 Bcf (totaling 234 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to the continual refinement of our drilling programs and reallocation of capital to areas providing the greatest opportunities to improve efficiencies, recoveries, and rates of return, (ii) downward revisions of 21 MMBo and 216 Bcf (totaling 57 MMBoe) from the removal of PUD reserves due to changes in anticipated well densities and other factors, (iii) upward price revisions of 21 MMBo and 31 Bcf (totaling 26 MMBoe) due to an increase in average crude oil and natural gas prices in 2018 compared to 2017, and (iv) net downward revisions of 2 MMBo and 11 Bcf (totaling 4 MMBoe) due to changes in ownership interests, operating costs, anticipated production performance, and other factors.

Extensions, discoveries and other additions. Extensions, discoveries and other additions for each of the three years reflected in the table above were due to successful drilling and completion activities and continual refinement of our drilling programs in the Bakken, SCOOP, and STACK plays. Proved reserve additions in the Bakken totaled 251 MMBoe, 148 MMBoe, and 73 MMBoe for 2018, 2017, and 2016, respectively, while reserve additions in SCOOP totaled 186 MMBoe, 53 MMBoe, and 97 MMBoe for 2018, 2017, and 2016, respectively. Additionally, reserve additions in STACK totaled 128 MMBoe, 39 MMBoe, and 79 MMBoe in 2018, 2017, and 2016, respectively. See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2018 drilling activities.

Sales of minerals in place. We had no individually significant dispositions of proved reserves in the past three years.

Purchases of minerals in place. We had no individually significant acquisitions of proved reserves in the past three years. The increase in acquired reserves in 2018 compared to prior years was due to higher mineral acquisition spending.

Proved Undeveloped Reserves

All of our PUD reserves at December 31, 2018 are located in the Bakken, SCOOP, and STACK plays, our most active development areas, with those plays comprising 52%, 33%, and 15%, respectively, of our total PUD reserves at year-end 2018. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2018. Our PUD reserves at December 31, 2018 include 89 MMBoe of reserves associated with wells where drilling has occurred but the wells have not been completed or are completed but not producing ("DUC wells"). Our DUC wells are classified as PUD reserves when relatively major expenditures are required to complete and produce from the wells.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves at December 31, 2017	322,242	2,441,120	729,094
Revisions of previous estimates	(95,168)	(1,229,127)	(300,022)
Extensions and discoveries	222,122	1,612,969	490,950
Sales of minerals in place	(1,963)	(24,327)	(6,017)
Purchases of minerals in place	2,457	33,563	8,051
Conversion to proved developed reserves	(40,419)	(206,873)	(74,897)
Proved undeveloped reserves at December 31, 2018	409,271	2,627,325	847,159

Revisions of previous estimates. As previously discussed, in 2018 we removed 74 MMBo and 960 Bcf (totaling 234 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to the continual refinement of our drilling programs. Of these removals, 53 MMBo and 111 Bcf (totaling 72 MMBoe) was related to Bakken properties, 20 MMBo and 734 Bcf (totaling 142 MMBoe) was related to SCOOP properties, and 1 MMBo and 115 Bcf (totaling 20 MMBoe) was related to STACK properties. Additionally, aforementioned changes in anticipated well densities and other factors resulted in downward PUD reserve revisions of 21 MMBo and 216 Bcf (totaling 57 MMBoe) in 2018. Increases in average crude oil and natural gas prices in 2018 resulted in upward price revisions of 3 MMBo. Finally, changes in ownership interests, operating costs, anticipated production performance, and other factors resulted in net downward PUD reserve revisions of 3 MMBo and 53 Bcf (totaling 12 MMBoe) in 2018.

Extensions and discoveries. Extensions and discoveries were due to successful drilling activities and continual refinement of our drilling programs in the Bakken, SCOOP and STACK plays. PUD reserve additions in the Bakken totaled 159 MMBo and 410 Bcf (totaling 228 MMBoe) in 2018, while SCOOP PUD reserve additions totaled 53 MMBo and 662 Bcf (totaling 163 MMBoe) and STACK PUD reserve additions totaled 10 MMBo and 541 Bcf (totaling 100 MMBoe).

Purchases of minerals in place. Acquired PUD reserves in 2018 primarily reflect mineral acquisitions during the year, none of which were individually significant.

Conversion to proved developed reserves. In 2018, we developed approximately 19% of our PUD locations and 10% of our PUD reserves booked as of December 31, 2017 through the drilling and completion of 330 gross (122 net) development wells at an aggregate capital cost of $693 million incurred in 2018. PUD conversions in the Bakken totaled 33 MMBo and 82 Bcf (totaling 47 MMBoe) in 2018, while SCOOP PUD conversions totaled 6 MMBo and 36 Bcf (totaling 12 MMBoe) and STACK PUD conversions totaled 1 MMBo and 89 Bcf (totaling 16 MMBoe). These activities resulted in the conversion in 2018 of 15%, 4%, and 18%, respectively, of our Bakken, SCOOP, and STACK PUD reserves booked at year-end 2017.

In response to the significant improvement in crude oil prices in 2018, we refined our drilling programs to concentrate our efforts in areas and formations in Oklahoma and North Dakota offering the best opportunities to accelerate oil-weighted production growth. As part of this effort, we reallocated capital and rigs away from areas in the SCOOP and STACK plays having higher concentrations of natural gas to oil-weighted areas and formations. These factors resulted in the deferral or removal of previously planned PUD development projects primarily in the SCOOP play, which impacted our conversion of PUD reserves in 2018.

Development plans. We have acquired substantial leasehold positions in the Bakken, SCOOP and STACK plays. Our drilling programs to date in those areas have focused on proving our undeveloped leasehold acreage through strategic drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations (i.e., categorized as held by production) and resulting in a reduced amount of leasehold acreage in the primary term of the lease. While we may opportunistically drill strategic exploratory wells, a substantial portion of our future capital expenditures will be focused on developing our PUD locations, including our drilled but not completed locations. Our inventory of DUC wells classified as PUDs total 348 gross (141 net) operated and non-operated locations at December 31, 2018 and represent

10% of our PUD reserves at that date. The costs to drill our uncompleted wells were incurred prior to December 31, 2018 and only the remaining completion costs are included in future development plans.

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $2.5 billion in 2019, $2.2 billion in 2020, $1.7 billion in 2021, $1.4 billion in 2022, and $1.4 billion in 2023. These capital expenditure projections have been established based on an expectation of drilling and completion costs, available cash flows, borrowing capacity, and the commodity price environment in effect at the time of preparing our reserve estimates and may be adjusted as market conditions evolve. Development of our existing PUD reserves at December 31, 2018 is expected to occur within five years of the date of initial booking of the PUDs. PUD reserves not expected to be drilled within five years of initial booking because of changes in business strategy or for other reasons have been removed from our reserves at December 31, 2018. We had no PUD reserves at December 31, 2018 that remain undeveloped beyond five years from the date of initial booking.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Ryder Scott, our independent reserves evaluation consulting firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 98% of our PV-10 and 98% of our total proved reserves as of December 31, 2018 included in this Form 10-K. The Ryder Scott technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Refer to Exhibit 99 included with this Form 10-K for further discussion of the qualifications of Ryder Scott personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team is in contact regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott’s preparation of the year-end reserves estimates. Proved reserves information is reviewed by our Audit Committee with representatives of Ryder Scott and by our internal technical staff before the information is filed with the SEC on Form 10-K. Additionally, certain members of our senior management review and approve the Ryder Scott reserves report and on a semi-annual basis review any internal proved reserves estimates.

Our Vice President—Corporate Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, an MBA in Finance and 34 years of industry experience with positions of increasing responsibility in operations, acquisitions, engineering and evaluations. He has worked in the area of reserves and reservoir engineering most of his career and is a member of the Society of Petroleum Engineers. The Vice President—Corporate Reserves reports directly to our Vice Chairman of Strategic Growth Initiatives. The reserves estimates are reviewed and approved by the Company's President and certain other members of senior management.

Proved Reserves, Standardized Measure, and PV-10 Sensitivities

Our year-end 2018 proved reserves, Standardized Measure, and PV-10 estimates were prepared using 2018 average first-day-of-the-month prices of $65.56 per Bbl for crude oil and $3.10 per MMBtu for natural gas ($61.20 per Bbl for crude oil and $3.22 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may be materially higher or lower than those used in our year-end estimates.

Provided below are sensitivities illustrating the potential impact on our estimated proved reserves, Standardized Measure, and PV-10 at December 31, 2018 under different commodity price scenarios for crude oil and natural gas. In these sensitivities, all factors other than the commodity price assumption have been held constant for each well. These sensitivities demonstrate the impact that changing commodity prices may have on estimated proved reserves, Standardized Measure, and PV-10 and there is no assurance these outcomes will be realized.

The crude oil price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain crude oil price scenarios, with natural gas prices being held constant at the 2018 average first-day-of-the-month price of $3.10 per MMBtu.

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The natural gas price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under certain natural gas price scenarios, with crude oil prices being held constant at the 2018 average first-day-of-the-month price of $65.56 per Bbl.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2018:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	950,649	558,662	136,740	85,817	1,087,389	644,479
Montana Bakken	171,663	137,622	17,866	10,134	189,529	147,756
Red River units	158,077	139,796	20,462	9,821	178,539	149,617
Other	88,615	62,330	70,095	58,471	158,710	120,801
South Region:						
SCOOP	257,866	152,607	194,483	103,027	452,349	255,634
STACK	254,539	139,036	153,320	89,602	407,859	228,638
Other	61,744	28,971	70,748	33,380	132,492	62,351
East Region	943	848	158,613	135,490	159,556	136,338
Total	1,944,096	1,219,872	822,327	525,742	2,766,423	1,745,614

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2018 scheduled to expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates or the leases are renewed.

	2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	3,050	1,669	29,684	20,401	32,530	23,205
Montana Bakken	400	400	—	—	1,480	1,480
Red River units	3,119	1,365	—	—	—	—
Other	20,417	13,963	3,755	1,343	17,217	17,217
South Region:						
SCOOP	68,187	33,901	53,178	29,820	26,443	12,797
STACK	60,317	32,535	49,944	34,018	18,837	13,555
Other	28,115	12,005	24,094	12,094	1,164	721
East Region	55,347	40,336	11,728	10,164	969	370
Total	238,952	136,174	172,383	107,840	98,640	69,345

Drilling Activity

During the three years ended December 31, 2018, we drilled and completed exploratory and development wells as set forth in the table below:

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	4	1.0	34	9.0	39	11.4
Natural gas	9	4.6	9	3.1	15	4.2
Dry holes	—	—	—	—	—	—
Total exploratory wells	13	5.6	43	12.1	54	15.6
Development wells:						
Crude oil	636	213.7	474	175.4	245	54.7
Natural gas	151	39.1	91	26.8	66	21.6
Dry holes	—	—	—	—	—	—
Total development wells	787	252.8	565	202.2	311	76.3
Total wells	800	258.4	608	214.3	365	91.9

As of December 31, 2018, there were 490 gross (212 net) operated and non-operated wells that have been spud and are in the process of drilling, completing or waiting on completion.

Summary of Crude Oil and Natural Gas Properties and Projects

In the following discussion, we review our budgeted number of wells and capital expenditures for 2019 in our key operating areas. Our 2019 capital budget has been set based on an expectation of available cash flows. Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our spending should commodity prices decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures.

The following table provides information regarding well counts and budgeted capital expenditures for 2019.

	2019 Plan		
	Gross wells (1)	Net wells (1)	Capital expenditures (in millions) (2)
Bakken	437	148	$ 1,063
Oklahoma	228	109	1,102
Total exploration and development	665	257	$ 2,165
Land (3)			205
Capital facilities, workovers and other corporate assets			228
Seismic			2
Total 2019 capital budget			$ 2,600

(1) Represents operated and non-operated wells expected to have first production in 2019.

(2) Represents total capital expenditures for operated and non-operated wells expected to have first production in 2019 and wells spud that will be in the process of drilling, completing or waiting on completion as of year-end 2019.

(3) Includes $125 million of planned spending for mineral acquisitions under our new relationship with Franco-Nevada Corporation described in Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests. With a carry structure in place, Continental will recoup $100 million, or 80%, of such acquisition spending from Franco-Nevada.

North Region

Our properties in the North region represented 55% of our total proved reserves as of December 31, 2018 and 60% of our average daily Boe production for the fourth quarter of 2018. Our principal producing properties in the North region are located in the Bakken field.

Bakken Field

The Bakken field of North Dakota and Montana is one of the largest crude oil resource plays in the United States. We are a leading producer, leasehold owner and operator in the Bakken. As of December 31, 2018, we controlled one of the largest leasehold positions in the Bakken with approximately 1.3 million gross (792,200 net) acres under lease. Our total Bakken production averaged 183,836 Boe per day for the fourth quarter of 2018, up 11% from the 2017 fourth quarter. For the year ended December 31, 2018, our average daily Bakken production increased 26% over 2017. We increased our drilling and well completion activities in the Bakken in 2018 in response to improved crude oil prices. In 2018, we participated in the drilling and completion of 496 gross (169 net) wells in the Bakken compared to 370 gross (145 net) wells in 2017. Our 2018 activities in the Bakken focused on ongoing development of high rate-of-return areas in core parts of the play.

Our Bakken properties represented 52% of our total proved reserves at December 31, 2018 and 57% of our average daily Boe production for the 2018 fourth quarter. Our total proved Bakken field reserves as of December 31, 2018 were 798 MMBoe, an increase of 26% compared to December 31, 2017 primarily due to reserves added from our drilling program and continued improvement in recoveries driven by advances in optimized completion designs. Our inventory of proved undeveloped drilling locations in the Bakken totaled 1,629 gross (930 net) wells as of December 31, 2018.

In 2019, we plan to invest approximately $1.06 billion in the Bakken play to drill, complete and initiate production on 437 gross (148 net) operated and non-operated wells. We plan to average approximately six operated rigs and four well completion crews in the Bakken throughout 2019. Our 2019 drilling and completion activities will focus on core parts of the Bakken that provide opportunities to improve capital efficiency, reduce finding and development costs, grow our oil-weighted production, and improve recoveries and rates of return.

South Region

Our properties in the South region represented 45% of our total proved reserves as of December 31, 2018 and 40% of our average daily Boe production for the fourth quarter of 2018. Our principal producing properties in the South region are located in the SCOOP and STACK areas of Oklahoma.

SCOOP

The SCOOP play extends across Garvin, Grady, Stephens, Carter, McClain and Love counties in Oklahoma and contains crude oil and condensate-rich fairways as delineated by numerous industry wells. We are a leading producer, leasehold owner and operator in the SCOOP play. As of December 31, 2018, we controlled one of the largest leasehold positions in SCOOP with approximately 452,300 gross (255,600 net) acres under lease.

Our SCOOP leasehold has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation in Oklahoma. In recent years, our drilling activities have resulted in the vertical expansion of our SCOOP Woodford position with discoveries of the SCOOP Springer and Sycamore formations, which are located directly above the Woodford formation. Our Springer and Sycamore positions supplement our Woodford leasehold and expand our resource potential and inventory in the play.

SCOOP represented 30% of our total proved reserves as of December 31, 2018 and 21% of our average daily Boe production for the fourth quarter of 2018. Production in SCOOP averaged 67,244 Boe per day during the fourth quarter of 2018, up 8% compared to the 2017 fourth quarter. For the year ended December 31, 2018, average daily production in SCOOP increased 6% compared to 2017, reflecting increased drilling and completion activities in 2018. We participated in the drilling and completion of 148 gross (48 net) wells in SCOOP during 2018 compared to 77 gross (20 net) wells in 2017. Proved reserves in SCOOP totaled 459 MMBoe as of December 31, 2018, a decrease of 7% compared to December 31, 2017 primarily due to the aforementioned removal of PUD reserves no longer scheduled to be drilled within five years of initial booking partially offset by new reserve extensions and discoveries. Our inventory of proved undeveloped drilling locations in SCOOP totaled 471 gross (248 net) wells as of December 31, 2018.

Our 2018 activities in SCOOP were focused on a new development project in the play named Project SpringBoard. SpringBoard is a massive, multi-year, crude oil project controlled and operated by Continental that covers approximately 73 square miles of contiguous leasehold in Grady County, Oklahoma where we are concurrently developing three stacked reservoirs in the Springer, Sycamore, and Woodford formations. These reservoirs are being developed in rows to maximize

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efficiencies and rates of return through the orderly sequencing of drilling and completion activities. This row development strategy allows us to realize significant cost savings. In addition to cost saving benefits, our SpringBoard production benefits from access to premium sales markets through existing pipeline infrastructure, making our SpringBoard sales price realizations among the best in the Company. Additionally, water pipeline and recycling facilities are in place to allow for uninterrupted flow back and recycling capabilities to support timely completion activities in the project. Project SpringBoard marks the beginning of full scale development of our SCOOP oil assets, following years of leasing, exploration, and delineation drilling, and is expected to have a meaningful impact on the Company's oil-weighted production growth in 2019.

STACK

STACK is a significant resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. As of December 31, 2018, we controlled one of the largest leasehold positions in STACK with approximately 407,900 gross (228,600 net) acres under lease. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma where we believe the reservoirs are typically thicker and deliver superior production rates relative to normal-pressured areas of the STACK petroleum system.

Our STACK properties represented 15% of our total proved reserves as of December 31, 2018 and 19% of our average daily Boe production for the fourth quarter of 2018. Production in STACK increased to an average rate of 62,947 Boe per day during the fourth quarter of 2018, up 31% over the 2017 fourth quarter due to additional wells being completed and producing. For the year ended December 31, 2018, average daily production in STACK grew 55% over 2017. We participated in the drilling and completion of 154 gross (40 net) wells in STACK during 2018 compared to 160 gross (49 net) wells in 2017. Our 2018 activities were focused on accelerating the development of our oil and liquids-rich assets in the play. Highlighting our 2018 activity in the play was the completion of three units (Jalou, Homsey, Simba) targeting the Meramec formation in the over-pressured oil and condensate windows of STACK. These three units produced outstanding results that confirmed our unit development model and the economic producibility of the reservoirs in the play.

Proved reserves in STACK increased 38% year-over-year to 230 MMBoe as of December 31, 2018 due to reserves added from our drilling program and continued improvement in recoveries driven by advances in optimized completion designs. Our inventory of proved undeveloped drilling locations in STACK totaled 262 gross (84 net) wells as of December 31, 2018.

In Oklahoma, for 2019 we plan to invest an aggregate of approximately $1.10 billion to drill, complete and initiate production on 228 gross (109 net) operated and non-operated wells in the SCOOP and STACK areas combined. We plan to average approximately 19 operated rigs, with 12 rigs focused on Project SpringBoard, and five well completion crews in Oklahoma throughout 2019. Our 2019 activities in SCOOP will focus on continued row development in Project SpringBoard and achieving operational and technical advancements aimed at further improving capital efficiencies, oil-weighted production growth, and rates of return. Our 2019 activities in STACK will focus on continued development of oil and liquids-rich assets in the over-pressured windows of the play and improving capital efficiencies, recoveries, and rates of return.

Production and Price History

The following table sets forth information concerning our production results, average sales prices and production costs for the years ended December 31, 2018, 2017 and 2016 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2018.

	Year ended December 31,		
	2018	2017	2016
Net production volumes:			
Crude oil (MBbls)			
North Dakota Bakken	45,775	35,964	31,723
SCOOP	6,918	5,726	6,807
STACK	3,582	3,166	1,552
Total Company	61,384	50,536	46,850
Natural gas (MMcf)			
North Dakota Bakken	78,448	59,232	50,532
SCOOP	99,397	98,563	102,032
STACK	101,267	60,325	27,983
Total Company	284,730	228,159	195,240
Crude oil equivalents (MBoe)			
North Dakota Bakken	58,849	45,836	40,145
SCOOP	23,484	22,153	23,813
STACK	20,460	13,220	6,216
Total Company	108,839	88,562	79,390
Average net sales prices (1):			
Crude oil ($/Bbl)			
North Dakota Bakken	$58.37	$45.21	$34.33
SCOOP	62.74	47.96	38.87
STACK	61.97	49.68	41.95
Total Company	59.19	45.70	35.51
Natural gas ($/Mcf)			
North Dakota Bakken	$3.33	$2.97	$1.05
SCOOP	3.41	3.26	2.24
STACK	2.38	2.43	1.87
Total Company	3.01	2.93	1.87
Crude oil equivalents ($/Boe)			
North Dakota Bakken	$49.83	$39.32	$28.45
SCOOP	32.88	26.93	20.71
STACK	22.68	22.89	18.88
Total Company	41.25	33.65	25.55
Average costs per Boe:			
Production expenses ($/Boe)			
North Dakota Bakken	$4.40	$4.40	$4.59
SCOOP	1.34	1.01	1.13
STACK	1.21	1.22	1.00
Total Company	3.59	3.66	3.65
Production taxes ($/Boe)	$3.25	$2.35	$1.79
General and administrative expenses ($/Boe)	$1.69	$2.16	$2.14
DD&A expense ($/Boe)	$17.09	$18.89	$21.54

(1) See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of net sales prices, which are non-GAAP measures for 2018.

The following table sets forth information regarding our average daily production by region for the fourth quarter of 2018:

	Fourth Quarter 2018 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	139,338	228,124	177,358
Montana Bakken	4,998	8,881	6,478
Red River units			
Cedar Hills	6,389	1,255	6,598
Other Red River units	2,048	2,385	2,446
Other	33	—	33
South Region:			
SCOOP	21,332	275,471	67,244
STACK	12,402	303,272	62,947
Other	394	3,014	897
Total	186,934	822,402	324,001

Productive Wells

Gross wells represent the number of wells in which we own a working interest and net wells represent the total of our fractional working interests owned in gross wells. The following table presents the total gross and net productive wells by region and by crude oil or natural gas completion as of December 31, 2018. One or more completions in the same well bore are counted as one well.

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	4,506	1,446	—	—	4,506	1,446
Montana Bakken	401	263	—	—	401	263
Red River units						
Cedar Hills	135	129	—	—	135	129
Other Red River units	128	114	—	—	128	114
Other	2	2	—	—	2	2
South Region:						
SCOOP	335	184	438	126	773	310
STACK	257	82	353	123	610	205
Other	101	80	126	40	227	120
Total	5,865	2,300	917	289	6,782	2,589

Title to Properties

As is customary in the crude oil and natural gas industry, upon initiation of acquiring oil and gas leases covering fee mineral interests on undeveloped lands which do not have associated proved reserves, contract landmen conduct a title examination of courthouse records and production databases to determine fee mineral ownership and availability. Title, lease forms and terms are reviewed and approved by Company landmen prior to consummation.

For acquisitions from third parties, whether lands are producing crude oil and natural gas or non-producing, Company and contract landmen perform title examinations at applicable courthouses, obtain physical well site inspections, and examine the seller's internal records (land, legal, operational, production, environmental, well, marketing and accounting) upon execution of a mutually acceptable purchase and sale agreement. Company landmen may also procure an acquisition title opinion from outside legal counsel on higher value properties.

Prior to the commencement of drilling operations, Company landmen procure an original title opinion, or supplement an existing title opinion, from outside legal counsel and perform curative work to satisfy requirements pertaining to material title defects, if any. Company landmen will not approve commencement of drilling operations until material title defects pertaining to the Company's interest are cured.

The Company has cured material title opinion defects as to Company interests on substantially all of its producing properties and believes it holds at least defensible title to its producing properties in accordance with standards generally accepted in the crude oil and natural gas industry. The Company's crude oil and natural gas properties are subject to customary royalty and leasehold burdens which do not materially interfere with the Company's interest in the properties or affect the Company's carrying value of such properties.

Marketing and Major Customers

We sell most of our operated crude oil production to crude oil refining companies or midstream marketing companies at major market centers. In the Bakken, SCOOP and STACK areas, we have significant volumes of production directly connected to pipeline gathering systems, with the remaining balance of production being primarily transported by truck either directly to a refinery or to a point on a pipeline system for further delivery. We do not transport any of our oil production prior to sale by rail, but several purchasers of our Bakken production are connected to rail delivery systems and may choose those methods to transport the oil they purchase from us. We sell some operated crude oil production at the lease. Our share of crude oil production from non-operated properties is marketed at the discretion of the operators.

We sell our operated natural gas production to midstream customers at our lease locations based on market prices in the field where the sales occur. These contracts include multi-year term agreements, many with acreage dedication. Under certain arrangements, we have the right to take a volume of processed residue gas and/or natural gas liquids ("NGLs") in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement for the sale of our operated natural gas production. We currently take certain processed residue gas volumes in kind in lieu of monetary settlement, but we do not take NGL volumes. When we do take volumes in kind, we pay third parties to transport the residue gas volumes taken in kind to downstream delivery points, where we then sell to customers at prices applicable to those downstream markets. Sales at the downstream markets are mostly under monthly interruptible packaged volume deals, short term seasonal packages, and long term multi-year contracts. We continue to develop relationships and have the potential to enter into additional contracts with end-use customers, including utilities, industrial users, and liquefied natural gas exporters, for sale of products we elect to take in-kind in lieu of monetary settlement for our leasehold sales. Our share of natural gas production from non-operated properties is generally marketed at the discretion of the operators.

For the year ended December 31, 2018, sales to Valero Energy Corporation and its affiliates accounted for approximately 12% of our total crude oil and natural gas revenues. No other purchaser accounted for more than 10% of our total crude oil and natural gas revenues for 2018. The loss of any single purchaser will not have a material adverse effect on our operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive crude oil and natural gas 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. 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 economically in a highly competitive environment. In addition, as a result of the significant decrease in commodity prices in recent years, the number of providers of materials and services has decreased in the regions where we operate. As a result, the likelihood of experiencing competition and shortages of materials and services may be further increased in connection with any period of sustained commodity price recovery.

Regulation of the Crude Oil and Natural Gas Industry

Our operations are conducted onshore almost entirely in the United States. The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations, policies, and interpretations affecting our industry have been and are pervasive with the frequent imposition of new or increased requirements on us and other industry participants. These laws, regulations and other requirements often carry substantial penalties for failure to comply and may have a significant effect on our operations and may increase the cost of doing business and reduce our profitability. In addition, because public policy changes affecting the crude oil and natural gas industry are commonplace and because laws, rules and regulations may be enacted, amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws, rules and regulations. We do not expect future legislative or regulatory initiatives will affect us materially different than they would affect our similarly situated competitors.

The following is a discussion of significant laws, rules and regulations, as amended from time to time, that may affect us in the areas in which we operate.

Regulation of sales and transportation of crude oil and natural gas liquids

Our physical sales of crude oil and any derivative instruments relating to crude oil are subject to anti-market manipulation laws and related regulations enforced by the Federal Trade Commission (“FTC”) and the Commodity Futures Trading Commission (“CFTC”) that, among other things, prohibit fraudulent or deceptive conduct in connection with wholesale purchases or sales of crude oil and price manipulation in the commodity and futures markets. If we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

We transport most of our operated crude oil production to market centers using a combination of trucks and pipeline transportation facilities owned and operated by third parties. The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration establishes safety regulations relating to transportation of crude oil by pipeline. Further, our sales of crude oil are affected by the availability, terms and costs of transportation. The transportation of crude oil and natural gas liquids ("NGLs") is subject to rate and access regulation. The Federal Energy Regulatory Commission (“FERC”) regulates interstate crude oil and NGL pipeline transportation rates under the Interstate Commerce Act and the Energy Policy Act of 1992. In general, pipeline rates must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. Intrastate crude oil and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. As the interstate and intrastate transportation rates we pay are generally applicable to all comparable shippers, the regulation of such transportation rates will not affect us in a way that materially differs from the effect on our similarly situated competitors.

Further, interstate pipelines and intrastate common carrier pipelines must provide service on an equitable basis and offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When such pipelines operate at full capacity we are subject to proration provisions, which are described in the pipelines’ published tariffs. We generally will have access to crude oil pipeline transportation services to the same extent as our similarly situated competitors.

Beginning in the 1970s, the United States regulated the exportation of petroleum and petroleum products, which restricted the markets for these commodities and affected sales prices. However, in December 2015 the U.S. Congress passed legislation eliminating the ban on crude oil exports beginning in January 2016. From time to time we may sell our operated crude oil production at market centers in the United States to third parties who then subsequently export and sell the crude oil in international markets. The International Maritime Organization ("IMO"), an agency of the United Nations, has issued regulations requiring the maritime shipping industry to gradually reduce its carbon emissions over time by mandating a 1% improvement in the efficiency of fleets each year between 2015 and 2025. In conjunction with this initiative, the IMO has issued regulations requiring ship owners to lower the concentration of the sulfur content used in their fuels from 3.5% to 0.5% beginning in 2020. To achieve this goal, ship owners will either have to switch to more expensive higher quality marine fuel, invest in emissions-cleaning systems, or switch to alternative fuels such as liquefied natural gas. Third party compliance with the IMO's shipping regulations may result in exportation capacity constraints during the period in which tanker fleets are retrofitted to meet specifications, thereby inhibiting a third party's ability to transport and sell our crude oil production overseas, which may have a material impact on the markets and prices for various grades of domestic and international crude oil.

We do not own or operate pipeline or rail transportation facilities, rail cars, or infrastructure used to facilitate the exportation of crude oil. However, regulations that impact the domestic transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at market centers throughout the United States. We do not expect such regulations will affect us in a materially different way than similarly situated competitors.

Regulation of sales and transportation of natural gas

We are also required to observe the aforementioned anti-market manipulation laws and related regulations enforced by the FERC and CFTC in connection with physical sales of natural gas and derivative instruments relating to natural gas. Additionally, the FERC regulates interstate natural gas transportation rates and service conditions under the Natural Gas Act and the Natural Gas Policy Act of 1978, which affects the marketing of natural gas we produce, as well as revenues we receive for sales of our natural gas. The FERC has endeavored to increase competition and make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis and has issued a series of orders to implement its open access policies. We cannot provide any assurance the pro-competitive regulatory approach established by the FERC will continue. However, we do not believe any action taken by the FERC will affect us in a materially different way than similarly situated natural gas producers.

The gathering of natural gas, which occurs upstream of jurisdictional transmission services, is generally regulated by the states. Although its policies on gathering systems have varied in the past, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the potential to increase costs for our purchasers and reduce the revenues we receive for our natural gas stream. State regulation of natural gas gathering facilities generally includes various safety, environmental, and in some circumstances, equitable take requirements. We do not believe such regulations will affect us in a materially different way than our similarly situated competitors.

Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas we produce, as well as the revenues we receive for sales of our natural gas. 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 on a comparable basis, the regulation of intrastate natural gas transportation in states in which we operate will not affect us in a way that materially differs from our similarly situated competitors.

The U.S. Department of Energy ("U.S. DOE") regulates the terms and conditions for the exportation and importation of natural gas (including liquefied natural gas or "LNG"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a Free Trade Agreement ("FTA") with the United States providing for national treatment of trade in natural gas; however, the U.S. DOE's regulation of imports and exports from and to countries without an FTA is more comprehensive. The FERC also regulates the construction and operation of import and export facilities, including LNG terminals. Regulation of imports and exports and related facilities may materially affect natural gas markets and sales prices and could inhibit the development of LNG infrastructure.

Regulation of production

The production of crude oil and natural gas is regulated by a wide range of federal, state and local laws, rules, orders and regulations, which require, among other matters, permits for drilling operations, drilling bonds and reports concerning operations. Each of the states where we own and operate properties have laws and regulations governing conservation, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing, the plugging and abandonment of wells, the regulation of greenhouse gas emissions, and limitations or prohibitions on the venting or flaring of natural gas. These laws and regulations directly and indirectly limit the amount of crude oil and natural gas we can produce from our wells and the number of wells and locations we can drill, although we can and do apply for exceptions to such laws and regulations or to have reductions in well spacing. Moreover, each state generally imposes a production, severance or excise tax on the production and sale of crude oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with the above laws, rules, and regulations can result in substantial penalties. Our similarly situated competitors are generally subject to the same laws, rules, and regulations as we are.

Environmental regulation

General. We are subject to stringent and complex federal, state, and local laws, rules and regulations governing environmental compliance, including the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits to conduct exploration, drilling and production operations;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with crude oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas including areas containing endangered species of plants and animals;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

These laws, rules and regulations may also restrict the rate of crude oil and natural gas production below a rate otherwise possible. The regulatory burden on the crude oil and natural gas industry increases the cost of doing business and affects profitability. Additionally, the U.S. Congress and federal and state legislators and agencies frequently revise environmental laws, rules and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the crude oil and natural gas industry could have a significant impact on our operating costs and production of oil and gas.

Failure to comply with these and other laws, rules and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays in the permitting or performance of projects, the issuance of orders enjoining performance of some or all of our operations, and potential litigation. The following is a description of some of the environmental laws, rules and regulations that apply to our operations.

Air emissions and climate change. Federal, state and local laws and regulations have been and may be enacted to address concerns about the potential effects of carbon dioxide, methane and other identified “greenhouse gas” emissions on the environment and climate worldwide, generally referred to as “climate change.” For example, in October 2015 the U.S. Environmental Protection Agency ("EPA") revised the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.

With respect to climate change and the control of greenhouse gas emissions, recent federal regulatory initiatives have focused on reducing methane emissions from oil and gas operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements. For example, in June 2016 the EPA finalized new regulations (New Source Performance Standard Subpart OOOOa, commonly referred to as “Quad Oa”) setting methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities. The U.S. Department of Interior’s Bureau of Land Management (“BLM”) finalized similar regulations in November 2016 for new and existing oil and gas operations on federal lands. Following the change in U.S. presidential administrations in 2016, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, we cannot predict the scope of any final methane-related regulatory requirements or the cost to comply with such requirements. Some states have also imposed similar regulations on oil and gas operations, and it is possible new methane emission standards could be proposed in the future. However, we do not expect such measures will affect us in a materially different way from our similarly situated competitors.

At an international level, in December 2015 a global climate agreement was reached in Paris at the 21st Conference of Parties organized by the United Nations under the Framework Convention on Climate Change. The agreement, which goes into effect in 2020, resulted in nearly 200 countries, originally including the United States, committing to work towards limiting global warming and agreeing to a monitoring and review process of greenhouse gas emissions. The agreement includes binding and non-binding elements and did not require ratification by the U.S. Congress. Following the change in U.S. presidential administrations, in August 2017 the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris climate agreement.

While we cannot predict the outcome of legislative or regulatory initiatives related to climate change, we anticipate that initiatives to reduce greenhouse gas emissions will continue to develop. The adoption of state or federal legislation or regulatory programs to reduce greenhouse gas emissions, including methane and carbon dioxide, could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming hydrocarbons and thereby reduce demand for the crude oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce greenhouse gas emissions could have an adverse effect on our business, financial condition, results of operations, and cash flows.

Environmental protection and natural gas flaring. One of our environmental initiatives is the reduction of air emissions produced from our operations, particularly with respect to the flaring of natural gas from our operated well sites in the Bakken field of North Dakota. North Dakota statutes permit flaring of natural gas from a well that has not been connected to a gas gathering line for a period of one year from the date of a well’s first production. After one year, a producer is required to cap the well, connect it to a gas gathering line, find acceptable alternative uses for a percentage of the flared gas, or apply to the North Dakota Industrial Commission ("NDIC") for a written exemption for any future flaring; otherwise, the producer is required to pay royalties and production taxes based on the volume and value of the gas flared from the unconnected well. In addition, NDIC rules for new drilling permit applications also require the submission of gas capture plans addressing measures taken by operators to capture and not flare produced gas, regardless of whether it has been or will be connected within the first year of production. The NDIC currently requires us to capture 88% of the natural gas produced from a field, and beginning November 1, 2020 the target capture rate increases to 91%. Ongoing compliance with the NDIC’s flaring requirements or the imposition of any additional limitations on flaring could result in increased costs and have an adverse effect on our operations.

We continue to strive to reduce natural gas flaring as much as practicable, but our efforts may not always be successful or cost-effective. Increased emissions from our facilities due to flaring could subject our facilities to more stringent air emission permitting requirements, resulting in increased compliance costs and potential construction delays.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppant and additives under pressure into rock formations to stimulate crude oil and natural gas production. In recent years there has been public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to induce seismic events. As a result, several federal and state agencies are studying the environmental risks with respect to hydraulic fracturing, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 related to such activities. In June 2016, the EPA finalized a regulation under the Clean Water Act prohibiting discharges to publicly owned treatment works of wastewater from onshore unconventional oil and gas extraction facilities. It has not been our practice to discharge wastewater to publicly owned treatment works, so the impact of this regulation on us is not currently, and is not expected to be, material.

In December 2016 the EPA published a final study of the potential impacts of hydraulic fracturing activities on water resources in which the EPA indicated it found evidence that such activities can impact drinking water resources under some circumstances. In its final report, the EPA indicated it was not able to calculate or estimate the national frequency of impacts on drinking water resources from hydraulic fracturing activities or fully characterize the severity of impacts. Nonetheless, the results of the EPA’s study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

In March 2015, the BLM issued final rules related to the regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity, and handling of flowback water. However, the BLM subsequently rescinded the rules in December 2017. Litigation challenging the BLM's rescission has been filed by certain states and environmental groups and remains ongoing. As of December 31, 2018, we held approximately 59,700 net undeveloped acres on federal land, representing approximately 11% of our total net undeveloped acres.

In addition, regulators in states in which we operate have adopted or are considering additional requirements related to seismicity and its potential association with hydraulic fracturing. For example, the Oklahoma Corporation Commission (the “OCC”) has promulgated guidance for operators of crude oil and natural gas wells in certain seismically-active areas of the SCOOP and STACK plays in Oklahoma. The OCC's guidance provides for seismic monitoring and for implementation of mitigation procedures, which may include curtailment or even suspension of operations in the event of concurrent seismic events within a particular radius of operations of a magnitude exceeding 2.5 on the Richter scale. If seismic events exceeding the OCC guidance thresholds were to occur near our active stimulation operations on a frequent basis, they could have an adverse effect on our operations.

Waste water disposal. Underground injection wells are a predominant method for disposing of waste water from oil and gas activities. In response to seismic events near underground injection wells used for the disposal of oil and gas-related waste waters, federal and some state agencies are investigating whether such wells have caused increased seismic activity. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or imposed moratoria on the use of injection wells. Regulators in states in which we operate are considering additional requirements related to seismicity. For example, the OCC has adopted rules for operators of saltwater disposal wells in certain seismically-active areas in the Arbuckle formation of Oklahoma. These rules require, among other things, that disposal well operators conduct mechanical integrity testing or make certain demonstrations of such wells' respective depths that, depending on the depth, could require plugging the well and/or the reduction of volumes disposed in such wells. Oklahoma utilizes a "traffic light" system wherein the OCC reviews new or existing disposal wells for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. At the federal level, the EPA's current regulatory requirements for such wells do not require the consideration of seismic impacts when issuing permits. We cannot predict the EPA's future actions in this regard.

The introduction of new environmental initiatives and regulations related to the disposal of wastes associated with the exploration, development or production of hydrocarbons could limit or prohibit our ability to utilize underground injection wells. A lack of waste water disposal sites could cause us to delay, curtail or discontinue our exploration and development plans. Additionally, 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. These costs are commonly incurred by oil and gas producers and we do not believe the costs associated with the disposal of produced water will have a material adverse effect on our operations to any greater degree than other similarly situated competitors. In recent years we have increased our operation and use of water recycling and distribution facilities in Oklahoma that economically reuse stimulation water for both operational efficiencies and environmental benefits.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures are included within our overall capital and operating budgets and are not separately itemized. Although we believe our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you the passage of more stringent laws or regulations in the future will not materially impact our business, financial condition, results of operations or cash flows.

Employee Health and Safety. We are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulation under Title III of the federal superfund Amendment and Reauthorization Act and similar state laws and regulations require information be maintained about hazardous materials used or produced in operations and this information be provided to employees, state and local governmental authorities and citizens.

Employees

As of December 31, 2018, we employed 1,221 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Company Contact Information

Our corporate internet website is www.clr.com. Through the investor relations section of our website, we make available free of charge our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the SEC. For a current version of various corporate governance documents, including our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for various committees of our Board of Directors, please see our website. We intend to disclose amendments to, or waivers from, our Code of Business Conduct and Ethics by posting to our website. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

We intend to use our website as a means of disclosing material information and for complying with our disclosure obligations under SEC Regulation FD. Such disclosures will be included on our website in the "For Investors" section. Accordingly, investors should monitor that portion of our website in addition to following our press releases, SEC filings and public conference calls and webcasts.

We electronically file periodic reports and proxy statements with the SEC. The SEC maintains an internet website that contains reports, proxy and information statements, and other information registrants file with the SEC. The address of the SEC's website is www.sec.gov.

Our principal executive offices are located at 20 N. Broadway, Oklahoma City, Oklahoma 73102, and our telephone number at that address is (405) 234-9000.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all other information contained in this report in connection with an investment in our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of our securities could decline and you may lose all or part of your investment.

Substantial declines in commodity prices or extended periods of low commodity prices adversely affect our business, financial condition, results of operations and cash flows and our ability to meet our capital expenditure needs and financial commitments.

The prices we receive for sales of our crude oil and natural gas production impact our revenue, profitability, cash flows, access to capital, capital budget, rate of growth, and carrying value of our properties. Crude oil and natural gas are commodities and prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for crude oil and natural gas have been volatile and unpredictable. For example, during 2018 the NYMEX West Texas Intermediate ("WTI") crude oil and Henry Hub natural gas spot prices ranged from approximately $44 to $77 per barrel and $2.49 to $6.24 per MMBtu, respectively. Commodity prices will likely remain volatile and unpredictable in 2019 and beyond.

We have hedged the majority of our forecasted 2019 natural gas production. Our future crude oil production is currently unhedged and is directly exposed to continued volatility in market prices, whether favorable or unfavorable.

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

- worldwide, domestic, and regional economic conditions impacting the supply of, and demand for, crude oil, natural gas, and natural gas liquids;
- the actions of the Organization of Petroleum Exporting Countries and other producing nations;
- the nature and extent of domestic and foreign governmental laws, regulations, and taxation, including environmental laws and regulations governing the imposition of trade restrictions and tariffs;
- the level of global, national, and regional crude oil and natural gas exploration and production activities;
- the level of global, national, and regional crude oil and natural gas inventories, which may be impacted by economic sanctions applied to certain producing nations;
- the level and effect of speculative trading in commodity futures markets;
- the relative strength of the United States dollar compared to foreign currencies;
- the price and quantity of imports of foreign crude oil;
- the price and quantity of exports of crude oil or liquefied natural gas from the United States;
- military and political conditions in, or affecting other, crude oil-producing and natural gas-producing nations;
- localized supply and demand fundamentals;
- the cost and availability, proximity and capacity of transportation, processing, storage and refining facilities for various quantities and grades of crude oil, natural gas, and natural gas liquids;
- adverse weather conditions and natural disasters;
- technological advances affecting energy production and consumption;
- the effect of worldwide energy conservation and environmental protection efforts; and
- the price and availability of alternative fuels or other energy sources.

Sustained material declines in commodity prices reduce cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; may limit our ability to borrow money or raise additional capital; and may reduce our proved reserves and the amount of crude oil and natural gas we can economically produce.

In addition to reducing our revenue, cash flows and earnings, depressed prices for crude oil and/or natural gas may adversely affect us in a variety of other ways. If commodity prices decrease substantially, some of our exploration and development projects could become uneconomic, and we may also have to make significant downward adjustments to our estimated proved reserves and our estimates of the present value of those reserves. If these price effects occur, or if our estimates of production or economic factors change, accounting rules may require us to write down the carrying value of our crude oil and/or natural gas properties.

Lower commodity prices may also lead to reductions in our drilling and completion programs, which may result in insufficient production to satisfy our transportation and processing commitments. If production is not sufficient to meet our commitments we would incur deficiency fees that would need to be paid absent any cash inflows generated from the sale of production.

Lower commodity prices may also reduce our access to capital and lead to a downgrade or other negative rating action with respect to our credit rating. A downgrade of our credit rating could negatively impact our cost of capital, increase the borrowing costs under our revolving credit facility, and limit our ability to access capital markets and execute aspects of our business plans. As a result, substantial declines in commodity prices or extended periods of low commodity prices may materially and adversely affect our future business, financial condition, results of operations, cash flows, liquidity and ability to finance planned capital expenditures and commitments.

Volatility in the financial markets or in global economic factors, including consequences resulting from international trade disputes and tariffs, could adversely impact our business.

United States and global economies may experience periods of volatility and uncertainty from time to time, resulting in unstable consumer confidence, diminished consumer demand and spending, diminished liquidity and credit availability, and inability to access capital markets. In recent years, certain global economies have experienced periods of political uncertainty, slowing economic growth, rising interest rates, changing economic sanctions, and currency volatility. These global macroeconomic conditions may have a negative impact on commodity prices and the availability and cost of materials used in our industry, which in turn could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The current administration in the United States has expressed concerns in recent years about imports from countries it perceives are engaging in unfair trade practices. In 2018, the United States government initiated tariffs on certain imported goods and has raised the possibility of imposing tariff increases on such goods or expanding the scope of tariffs to include other types of imported goods. In response, certain foreign governments, most notably China, have imposed retaliatory tariffs on certain goods their countries import from the United States. These and other events, including the United Kingdom's potential withdraw from the European Union, have contributed to increased economic uncertainty and diminished expectations for the global economy.

Trade restrictions or other governmental actions related to tariffs or trade policies have impacted, and have the potential to further impact, our business and industry. For instance, in 2018 the United States government imposed import tariffs of 25% on steel products and 10% on aluminum products, as well as quantitative restrictions on imports of steel and aluminum products from various countries. The oil and gas industry in the United States utilizes significant amounts of steel in the drilling and completion of new wells and for construction of facilities, pipelines, processing plants, and refineries. The steel required to meet the needs of our industry may not be domestically available in sufficient quantities, particularly in periods of favorable commodity prices. Thus, current and future tariffs may increase the cost of materials used in various aspects of upstream, midstream, and downstream oil and gas activities which, in turn, could increase our cost of doing business. Furthermore, the tariffs and quantitative import restrictions may cause disruption in the energy industry’s supply chain, resulting in the delay or cessation of drilling and completion efforts or the postponement or cancellation of new pipeline transportation projects the U.S. industry is relying on to transport its increasing levels of onshore production to market, as well as endangering U.S. liquefied natural gas export projects resulting in negative impacts on natural gas production. Additionally, trade and/or tariff disputes could have negative impacts on the domestic and global economies overall, which could result in reduced demand for crude oil and natural gas. Any of the above consequences could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our producing properties are located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A substantial portion of our producing properties is located in the Bakken field of North Dakota and Montana, with that area comprising approximately 56% of our crude oil and natural gas production and approximately 68% of our crude oil and natural gas revenues for the year ended December 31, 2018. Approximately 52% of our estimated proved reserves were located in the Bakken as of December 31, 2018. Additionally, in recent years we have significantly expanded our operations in Oklahoma with our increased activity in the SCOOP and STACK plays. Our properties in Oklahoma comprised approximately 41% of our crude oil and natural gas production and approximately 27% of our crude oil and natural gas revenues for the year ended December 31, 2018. Approximately 45% of our estimated proved reserves were located in Oklahoma as of December 31, 2018.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints; (ii) the availability of rigs, completion crews, equipment, field services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Bakken field and Oklahoma may be adversely affected by severe weather events such as floods, blizzards, ice storms and tornadoes, which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests, cyber attacks, or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on acceptable terms, which could lead to a decline in our crude oil and natural gas reserves, production and revenues. In addition, funding our capital expenditures with additional debt will increase our leverage and doing so with equity securities may result in dilution that reduces the value of your stock.

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. We have budgeted $2.6 billion for capital expenditures in 2019 of which approximately $2.2 billion is allocated to exploration and development activities. We may adjust our 2019 capital spending plans upward or downward depending on market conditions. Our 2019 capital budget, based on our current expectations of commodity prices and costs, is expected to be funded from operating cash flows and, if necessary, through borrowings under our credit facility. However, the sufficiency of our cash flows from operations and access to capital are subject to a number of variables, including but not limited to:

- the prices at which crude oil and natural gas are sold;
- the volume and value of our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell from existing wells;
- our ability to acquire, locate and produce new reserves;
- our ability to dispose of assets or enter into joint development arrangements on satisfactory terms; and
- the ability and willingness of our lenders to extend credit or of participants in the capital markets to invest in our senior notes or equity securities.

If oil and gas industry conditions weaken as a result of low commodity prices or other factors, we may not be able to generate sufficient cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or planned levels. A decline in cash flows from operations may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities.

We have a revolving credit facility with lender commitments totaling $1.5 billion that matures in April 2023. In the future, we may not be able to access adequate funding under our revolving credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments under the credit facility. Our lenders could decline to increase their commitments based on our financial condition, the financial condition of our industry or the economy as a whole or for other reasons beyond our control. Due to these and other factors, we cannot be certain that funding, if needed, will be available to the extent required or on terms we find acceptable. If operating cash flows are insufficient and we are unable to access funding or execute capital transactions when needed on acceptable terms, we may not be able to fully implement our business plans, fund our capital program and commitments, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due. Should any of the above risks occur, they could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Drilling for and producing crude 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 exploration, development and production activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, or develop 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. Our cost of drilling, completing and operating wells may be uncertain before drilling commences.

Risks we face while drilling include, but are not limited to, failing to place our well bore in the desired target producing zone; not staying in the desired drilling zone while drilling horizontally through the formation; failing to run our casing the entire length of the well bore; and not being able to run tools and other equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages; failing to run tools the entire length of the well bore during completion operations; not successfully cleaning out the well bore after completion of the final fracture stimulation stage; increased seismicity in areas near our completion activities; unintended interference of completion activities performed by us or by third parties with nearby operated or non-operated wells being drilled, completed, or producing; and failure of our optimized completion techniques to yield expected levels of production.

Further, many factors may curtail, delay or cancel scheduled drilling projects, including but not limited to:

- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment or qualified personnel;
- shortages of or delays in obtaining components used in fracture stimulation processes such as water and proppants;
- delays associated with suspending our operations to accommodate nearby drilling or completion operations being conducted by other operators;
- mechanical difficulties, fires, explosions, equipment failures or accidents, including ruptures of pipelines or train derailments;
- restrictions on the use of underground injection wells for disposing of waste water from oil and gas activities;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- decreases in, or extended periods of low, crude oil and natural gas prices;
- limited availability of financing with acceptable terms;
- title problems;
- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by us or by third party service providers;
- limitations in infrastructure, including transportation, processing and refining capacity, or markets for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements including permitting.

Any of the above events could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations and cash flows.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The Company’s current estimates of reserves could change, potentially in material amounts, in the future due to changes in commodity prices, business strategies, and other factors.

The process of estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions, production rates, drilling and operating expenses, and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves for information about our estimated crude oil and natural gas reserves, standardized measure of discounted future net cash flows, and PV-10 as of December 31, 2018.

In order to prepare reserve estimates, we must project production rates and the amount and timing of development expenditures. Proved undeveloped reserves generally must be drilled within five years from the date of initial booking under SEC reserve rules. Changes in the timing of development plans that impact our ability to develop such reserves in the required time frame have resulted, and will likely in the future result, in fluctuations in reserves between periods as reserves booked in one period may need to be removed in a subsequent period. In 2018, 234 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates associated with locations no longer scheduled to be drilled within five years from the date of initial booking.

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We must also analyze available geological, geophysical, production and engineering data in preparing reserve estimates. The extent, quality and reliability of this data can vary which in turn can affect our ability to model the porosity, permeability and pressure relationships in unconventional resources. The process also requires economic assumptions, based on historical data projected into the future, about crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds.

The prices used in calculating our estimated proved reserves are calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding 12 months. For the year ended December 31, 2018, average prices used to calculate our estimated proved reserves were $65.56 per Bbl for crude oil and $3.10 per MMBtu for natural gas ($61.20 per Bbl for crude oil and $3.22 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may be materially higher or lower than those used in our year-end estimates. NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2019 and February 1, 2019 averaged $50.34 per barrel and $3.03 per MMBtu, respectively. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, Standardized Measure, and PV-10 Sensitivities for proved reserve sensitivities under certain increasing and decreasing commodity price scenarios.

Actual future production, crude oil and natural gas sales prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves will vary and could vary significantly from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves, which in turn could have an adverse effect on the value of our assets. In addition, we may remove or adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development activities, changes in business strategies, prevailing crude oil and natural gas prices and other factors, some of which are beyond our control.

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

You should not assume the present value of future net revenues from our proved reserves is the current market value of our estimated crude oil and natural gas reserves. We base the estimated discounted future net revenues from proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future prices may be materially higher or lower than the average prices used in the calculations. Actual future net revenues from crude oil and natural gas properties will be affected by factors such as:

- the actual prices we receive for sales of crude oil and natural gas;
- the actual cost and timing of development and production expenditures;
- the timing and amount of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of costs in connection with the development and production of crude oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the use of a 10% discount factor, which is required by the SEC to be used to calculate discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil and natural gas industry. Any significant variances in timing or assumptions could materially affect the estimated present value of our reserves, which in turn could have an adverse effect on the value of our assets.

We may be required to further write down the carrying values of our crude oil and natural gas properties if commodity prices decline or our development plans change.

Accounting rules require we periodically review the carrying values of our crude oil and natural gas properties for possible impairment. Proved properties are reviewed for impairment on a field-by-field basis each quarter. We use the successful efforts method of accounting whereby the estimated future cash flows expected in connection with a field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value using a discounted cash flow model.

Based on specific market factors, prices, 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 values of our crude oil and natural gas properties. A write-down results in a non-cash charge to earnings. We have incurred impairment charges in the past and may incur additional impairment charges in the future, particularly if commodity prices decline, 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 crude oil and natural gas reserves, our reserves and production will decline, which could adversely affect our cash flows and results of operations.
Unless we conduct successful exploration, development and exploitation activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our 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 could be materially adversely affected.
The unavailability or high cost of drilling rigs, well completion crews, equipment, supplies, personnel and field services could adversely affect our ability to execute our exploration and development plans within budget and on a timely basis.
In the regions in which we operate, there have historically been shortages of drilling rigs, well completion crews, equipment, personnel, field services, and supplies, including key components used in fracture stimulation processes such as water and proppants, as well as high costs associated with these critical components of our operations. The demand for qualified and experienced field service providers and associated equipment, supplies, and materials can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages and/or higher costs. Such shortages or higher costs could delay the execution of our drilling and development plans or cause us to incur expenditures not provided for in our capital budget or to not achieve the rates of return we are targeting for our development program, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our crude oil and natural gas 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 associated with our business. Losses and liabilities arising from uninsured and under-insured events could materially and adversely affect our business, financial condition or results of operations. Our activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires and explosions;
- ruptures of pipelines or storage facilities;
- loss of product or property damage occurring as a result of transfer to a rail car or train derailments;
- personal injuries and death;
- adverse weather conditions and natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by us or by third party service providers.

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

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

- repair and remediation costs; and
- litigation.

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

Prospects we decide to drill may not produce crude oil or natural gas in expected quantities.

Prospects we decide to drill that do not produce crude oil or natural gas in expected quantities may adversely affect our results of operations, financial condition, and rates of return on capital employed. In this report, we describe some of our current prospects and plans to develop our key operating areas. It is not possible to predict with certainty whether any particular prospect will produce crude oil or natural gas in sufficient quantities to recover drilling and completion costs, achieve desired recoveries and rates of return, or be economically producible. The use of 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 crude oil or natural gas will be present in expected or economically producible quantities. We cannot assure you the wells we drill will be as productive as anticipated or whether the analogies we draw from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations is subject to a number of uncertainties, including crude oil and natural gas prices; the availability of capital, drilling rigs, well completion crews, and transportation and processing capacity; costs; drilling results; regulatory approvals; and other factors. If future drilling results do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if our potential drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations in sufficient quantities to achieve an economic return. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. Low commodity prices, reduced capital spending, lack of available drilling and completion rigs and crews and numerous other factors, many of which are beyond our control, could result in our failure to establish production on undeveloped acreage, and, if we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 60% of our total net undeveloped acreage at December 31, 2018. At that date, we had leases representing 136,174 net acres expiring in 2019, 107,840 net acres expiring in 2020, and 69,345 net acres expiring in 2021. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

At December 31, 2018, approximately 56% of our total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions may not prove to be accurate. Our reserve report at December 31, 2018 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $9.2 billion. We cannot be certain the estimated costs of the development of these reserves are accurate, development will occur as scheduled, or the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves as a result of our inability to fund necessary capital expenditures or otherwise, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any proved undeveloped reserves not developed within this five-year time frame. Such removals have occurred in the past and may occur in the future.

A removal of such reserves could adversely affect our operations. In 2018, 234 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates associated with locations no longer scheduled to be drilled within five years from the date of initial booking.

Our business depends on crude oil and natural gas transportation, processing, refining, and export facilities, most of which are owned by third parties.

The value we receive for our crude oil and natural gas production depends in part on the availability, proximity and capacity of gathering, pipeline and rail systems and processing, refining, and export facilities owned by third parties. The inadequacy or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells, the delay or discontinuance of development plans for properties, or higher operational costs associated with air quality compliance controls. Although we have some contractual control over the transportation of our products, changes in these business relationships or failure to obtain such services on acceptable terms could adversely affect our operations. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made for the sale or delivery of our products and acreage lease terminations could result if production is shut-in for a prolonged period.

The disruption of transportation, processing, refining, or export facilities due to labor disputes, maintenance, civil disturbances, international trade disputes, public protests, terrorist attacks, cyber attacks, adverse weather, natural disasters, seismic events, changes in tax and energy policies, federal, state and international regulatory developments, changes in supply and demand, equipment failures or accidents, including pipeline and gathering system ruptures or train derailments, and general economic conditions could negatively impact our ability to achieve the most favorable prices for our crude oil and natural gas production. We have no control over when or if access to such facilities would be restored or the impact on prices in the areas we operate. A significant shut-in of production in connection with any of the aforementioned items could materially affect our cash flows, and if a substantial portion of the impacted production fulfills transportation or processing commitments or is hedged at lower than market prices, those commitments or financial hedges would have to be paid from borrowings in the absence of sufficient operating cash flows.

Our operated crude oil and natural gas production is ultimately transported to downstream market centers in the United States primarily using transportation facilities and equipment owned and operated by third parties. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a discussion of regulations impacting the transportation of crude oil and natural gas. From time to time we may sell our operated crude oil production at market centers in the United States to third parties who then subsequently export and sell the crude oil in international markets. We do not currently own or operate infrastructure used to facilitate the transportation and exportation of crude oil; however, third party compliance with regulations that impact the transportation or exportation of our production may increase our costs of doing business and inhibit a third party's ability to transport and sell our production, whether domestically or internationally, the consequences of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our business depends on the availability of water and the ability to dispose of waste water from oil and gas activities. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling or completion sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection wells.

In addition, concerns have been raised in recent years about the potential for seismic events to occur from the use of underground injection wells, a predominant method for disposing of waste water from oil and gas activities. Rules and regulations have been developed in Oklahoma to address these concerns by limiting or eliminating the ability to use disposal wells in certain locations or increasing the cost of disposal. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or

imposed moratoria on the use of injection wells. Regulators in some states, including states in which we operate, have imposed or are considering additional requirements related to seismicity. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Waste water disposal for further discussion of regulations that affect us.
Compliance with existing or new environmental laws, regulations, and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of waste water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Our crude oil and natural gas exploration and production operations are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, occupational health and safety, the discharge of materials into the environment, and the protection of certain plant and animal species. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a description of the laws and regulations that affect us. In order to conduct operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from 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 revenues.

Failure to comply with laws and regulations may trigger a variety of administrative, civil and criminal enforcement investigations or actions, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, the issuance of orders or judgments limiting or enjoining future operations, criminal sanctions, or litigation. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, changes to existing laws or regulations, new laws or regulations, or changes in interpretations of laws and regulations may unfavorably impact us or the infrastructure used for transporting our products. Similarly, changes in regulatory policies and priorities could result in the imposition of new laws or regulations, such as increased reporting or audits. Any of these requirements could result in increased operating costs and could have a material adverse effect on our financial condition and results of operations. If such laws and regulations are adopted, they could result in, among other items, additional restrictions on hydraulic fracturing of wells, restrictions on the disposal of waste water from oil and gas activities, restrictions on emissions of greenhouse gases, modification of equipment utilized in our operations, changes to the calculation of royalty payments, restrictions on transportation of production, new safety requirements, and additional regulation of private energy commodity derivative and hedging activities. These and other potential laws, regulations, interpretations and other requirements could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. This, in turn, could have a material adverse effect on our financial condition, results of operations and cash flows.

Climate change legislation or regulations governing the emissions of “greenhouse gases” could result in increased operating costs, limitations in our ability to develop and produce reserves, and reduced demand for the crude oil, natural gas and natural gas liquids we produce.

In response to EPA findings that emissions of carbon dioxide, methane and other greenhouse gases endanger human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act establishing, among other things, Prevention of Significant Deterioration (“PSD”) pre-construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for greenhouse gas emissions are also required to meet “best available control technology” standards established on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Regulations related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

Certain previously existing climate-related regulations, such as those related to the control of methane emissions, have been, or are in the process of being, reviewed, suspended, revised, or rescinded. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Air emissions and climate change for further discussion of the status of such regulations. Undoing previously existing regulations has and likely will continue to involve lengthy notice-and-comment rulemaking, and the resulting decisions have been and likely will continue to be subject to litigation by opposition groups. Thus, the scope and impact of existing and potential future regulations remains substantially uncertain with respect to the implementation of climate-related public policies. However, given the long-term trend towards increasing regulation, future federal greenhouse gas regulations of the oil and gas industry remain possible, and certain states have separately imposed their own regulations on emissions from oil and gas production activities and other states may do so as well.

The implementation of, and compliance with, laws and regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions, install new equipment to reduce emissions of greenhouse gases associated with our operations, or limit our ability to develop and produce our reserves. In addition, substantial limitations on greenhouse gas emissions could adversely affect the demand for the crude oil and natural gas we produce, which could lower the value of our reserves and have a material adverse effect on our business, financial condition, results of operations and cash flows. Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has and may yet result in financial institutions, funds, and other sources of capital restricting or eliminating their investment in crude oil and natural gas activities. Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods or other climatic events. If any such effects were to occur as a result of climate change or otherwise, they could have an adverse effect on our assets and operations.

Federal and state laws and regulations relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and an inability to develop existing reserves or to book future reserves.

Hydraulic fracturing is an important and commonly used process in the completion of crude oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the high-pressure injection of water, sand or other proppant and additives into rock formations to stimulate crude oil and natural gas production. In recent years there has been public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to induce seismic events. As a result, several federal and state proposed and enacted laws and regulations have emerged which could increase the regulatory burden imposed on hydraulic fracturing. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Hydraulic fracturing for a description of the laws and regulations that affect us with respect to hydraulic fracturing.

States in which we operate have adopted or are considering adopting laws and regulations imposing more stringent permitting, disclosure, and well construction and reclamation requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating or prohibiting the time, place and manner of drilling activities or hydraulic fracturing activities. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards.

The adoption of any future federal, state or local law or implementing regulation imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process, or the discovery of groundwater contamination or other adverse environmental effects directly connected to hydraulic fracturing, could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. In the event regulations are adopted to prohibit or significantly limit the use of hydraulic fracturing in states in which we operate, it would have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves in our strategic plays. The inability to achieve a satisfactory economic return could cause us to curtail or discontinue our exploration and development plans, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Future legislation may impose new taxes on crude oil or natural gas activities, including eliminating or reducing certain federal income tax deductions currently available with respect to crude oil and natural gas exploration and development.

In previous years, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and gas exploration and production companies. Such proposed changes have included: (i) a repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of deductions for intangible drilling and exploration and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These tax deductions currently utilized within our industry were not impacted by the Tax Cuts and Jobs Act signed into law in the United States in December 2017. However, no prediction can be made as to whether any legislative changes will be proposed or enacted in the future that could eliminate or defer these or other tax deductions utilized within our industry. Any such changes could adversely affect our business, financial condition, results of operations and cash flows.

We are involved in legal proceedings that could result in substantial liabilities.

Like other similarly-situated oil and gas companies, we are, from time to time, involved in various legal proceedings in the ordinary course of business including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities, and other matters. The outcome of such legal matters often cannot be predicted with certainty. We vigorously defend ourselves in all such matters. However, if our efforts to defend ourselves are not successful, it is possible the outcome of one or more such proceedings could result in substantial liability, penalties, sanctions, judgments, consent decrees, or orders requiring a change in our business practices, which could have a material adverse on our business, financial condition, results of operations and cash flows. Judgments and estimates to determine accruals related to legal and other proceedings could change from period to period, and such changes could be material.

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

Our ability to acquire additional prospects and 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, securing long-term transportation and processing capacity, marketing crude oil and natural gas, and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for productive crude oil and natural gas 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, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, securing long-term transportation and processing capacity, marketing hydrocarbons, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns about hydraulic fracturing, oil spills, induced seismicity, and greenhouse gas emissions may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations or a reduction in demand for our products. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we or third party service providers need to conduct operations to be withheld, delayed, or burdened by requirements that restrict our ability to conduct our business.

Energy conservation measures or initiatives that stimulate demand for alternative forms of energy could reduce the demand for the crude oil and natural gas we produce.

Fuel conservation measures, climate change initiatives, governmental requirements for renewable energy resources, increasing consumer demand for alternative forms of energy, and technological advances in fuel economy and energy generation devices could reduce demand for the crude oil and natural gas we produce. The potential impact of changing demand for crude oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe weather events and natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe weather events and natural disasters such as hurricanes, tornadoes, seismic events, floods, blizzards and ice storms affecting the areas in which we operate, including our corporate headquarters, could have a material adverse effect on our operations or the operations of third party service providers. Such events may result in significant destruction of infrastructure, businesses, and homes and could disrupt the distribution and supply of crude oil and natural gas products in the impacted regions. The consequences of such events may include the evacuation of personnel; damage to and disruption of drilling rigs or transportation, processing, storage, refining, and export facilities; the shut-in of production resulting from an inability to transport crude oil or natural gas products to market centers and other factors; an inability to access well sites; destruction of information and communication systems; and the disruption of administrative and management processes, any of which could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations or cash flows.

Regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

From time to time, we may use derivative instruments to manage commodity price risk. In 2010, the U.S. Congress adopted the Dodd-Frank Act, which, among other provisions, established federal oversight and regulation of the over-the-counter derivatives market and required the Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to derivative transactions. If we do not qualify for an end user exemption from the Dodd-Frank Act requirements, the new regulations could increase the cost of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, lead to fewer potential counterparties, and increase our exposure to less creditworthy counterparties, any of which could limit our desire and ability to implement commodity price risk management strategies. If our use of derivatives becomes limited as a result of the regulations, our results of operations may become more volatile and our cash flows may be less predictable. While certain Dodd-Frank Act regulations are already in effect, certain aspects of the rulemaking have been repealed or have not been finalized and the ultimate effect of the regulations on our business remains uncertain.

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

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an ownership interest are operated by other companies and involve third-party working interest owners. As of December 31, 2018, non-operated properties represented 19% of our estimated proved developed reserves, 12% of our estimated proved undeveloped reserves, and 15% of our estimated total proved reserves. We have limited ability to influence or control the operations or future development of non-operated properties, including the marketing of oil and gas production, compliance with environmental, safety and other regulations, or the amount of expenditures required to fund the development and operation of such properties. Moreover, we are dependent on other working interest owners on these projects to fund their contractual share of capital and operating expenditures. These limitations and our dependence on the operators and other working interest owners for these projects could cause us to incur unexpected future costs and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our revolving credit facility and indentures for our senior notes contain certain covenants and restrictions that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our goals.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our revolving credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014.

At December 31, 2018, we had no outstanding borrowings on our credit facility and our consolidated net debt to total capitalization ratio, as defined, was 0.43 to 1.00. Our total debt would need to independently increase by approximately $8.1 billion above the existing level at December 31, 2018 (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would need to independently decrease by approximately $4.3 billion below the existing level at December 31, 2018 (excluding the after-tax impact of any non-cash impairment charges) to reach the maximum covenant ratio.

The indentures governing our senior notes contain covenants that, among other things, limit our ability to create liens securing certain indebtedness, enter into certain sale and leaseback transactions, and consolidate, merge or transfer certain assets.

The covenants in our revolving credit facility and senior note indentures may restrict our ability to expand or pursue our business strategies. Our ability to comply with the provisions of our revolving credit facility or senior note indentures may be impacted by changes in economic or business conditions, results of operations, or events beyond our control. The breach of any covenant could result in a default under our revolving credit facility or senior note indentures, in which case, depending on the actions taken by the lenders or trustees thereunder or their successors or assignees, could result in all amounts outstanding thereunder, together with accrued interest, to be due and payable. If our indebtedness is accelerated, our assets may not be sufficient to repay in full such indebtedness, which would have a material adverse effect our business, financial condition, results of operations, and cash flows.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

Our business and industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We rely heavily on digital technologies, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data; analyze seismic, drilling, completion and production information; manage production equipment; conduct reservoir modeling and reserves estimation; communicate with employees and business associates; perform compliance reporting and many other activities. The availability and integrity of these systems are essential for us to conduct our operations. Our business associates, including employees, vendors, service providers, financial institutions, and transporters, processors, and purchasers of our production are also heavily dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates have been and continue to be the target of cyber attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release or theft of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance of our systems and those of our business associates, may remain undetected for an extended period.

A cyber attack involving our information systems and related infrastructure, and/or that of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

- unauthorized access to or theft of seismic data, reserves information, strategic information, or other sensitive or proprietary information owned by us or by third parties could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production-related infrastructure could result in a loss of production or accidental discharge;
- a cyber attack on third party transportation, processing, storage, refining, or export facilities could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- a cyber attack involving commodity exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- corruption of our financial or operating data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- a cyber attack could result in unauthorized access to and release of personal or confidential information maintained by the Company.

Any of the above events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

The Company has established cyber security systems and controls intended to monitor threats, identify incidents and assess their impact, protect information, and mitigate data loss. The Company has also established disclosure controls and procedures in tandem with incident response protocols, including regular assessment of threats and incidents by a security oversight committee comprised of members of senior management and information technology personnel. These systems, controls, and procedures are intended to provide information about cyber security incidents so that such information can be timely processed and reported to the appropriate personnel; however, these systems, controls, and procedures may not identify all risks and threats we face, or may fail to protect data or mitigate the adverse effects of data loss. Our senior management makes materiality assessments and disclosure decisions and has implemented procedures to prohibit insider trading on the basis of material nonpublic information about cyber incidents; however, we cannot guarantee all of these efforts will be effective. Although we maintain systems, controls, and procedures to address cyber security risks, such measures cannot eliminate cyber security threats and incidents, and there remains a risk that we will experience a cyber breach, attack, or data loss incident and suffer adverse effects.

To our knowledge we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of a breach of our systems or those of our business associates. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the growth of cyber attacks has resulted in evolving legal and compliance matters which may impose significant costs that are likely to increase over time.

Increases in interest rates could adversely affect our business.

The U.S. Federal Reserve increased the benchmark federal funds interest rate on four separate occasions in 2018 and is forecasting additional increases in 2019. Our business and operating results can be adversely affected by increases in interest rates, the availability, terms of and cost of capital, or downgrades or other negative rating actions with respect to our credit rating. These factors could cause our cost of doing business to increase, limit our ability to pursue acquisition, disposition, or joint development opportunities, reduce cash flows used for drilling and completion activities, and place us at a competitive disadvantage. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our financial condition and results of operations.

Financial regulators are working to transition away from the London Interbank Offered Rate (“LIBOR”) as a reference rate for financial contracts by the end of 2021 and to develop benchmarks to replace LIBOR. Certain types of borrowings under our revolving credit facility, which matures in April 2023, are derived from the LIBOR reference rate. Our revolving credit agreement includes general provisions governing the establishment of an alternate rate of interest to the LIBOR-based rate that gives consideration to the then prevailing market convention for determining a rate of interest for comparable syndicated loans. At this time, the impact on the Company's borrowing costs, if any, under an alternative reference rate scenario is uncertain.

The inability of joint interest owners, derivative counterparties, significant customers, and service providers to meet their obligations to us may adversely affect our financial results.

Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($644 million in receivables at December 31, 2018); our joint interest and other receivables ($368 million at December 31, 2018); and counterparty credit risk associated with our derivative instrument receivables ($16 million at December 31, 2018). These counterparties may experience insolvency or liquidity issues and may not be able to meet their obligations and liabilities owed to us, particularly during a period of depressed commodity prices. Defaults by these counterparties could adversely impact our financial condition and results of operations.

Additionally, we rely on field service companies and midstream companies for services associated with the drilling and completion of wells and for certain midstream services. A worsening of the commodity price environment may result in a material adverse impact on the liquidity and financial position of the parties with whom we do business, resulting in delays in payment of, or non-payment of, amounts owed to us, delays in operations, loss of access to equipment and facilities and similar impacts. These events could have an adverse impact on our business, financial condition, results of operations and cash flows.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in commodity prices, from time to time we may enter into derivative instruments for a potentially significant portion of our production. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for a summary of our commodity derivative positions as of December 31, 2018. We do not designate any of our derivative instruments as hedges for accounting purposes and we record all derivatives on our balance sheet at fair value. Changes in the fair value of our derivatives are recognized in current period earnings. Accordingly, our earnings may fluctuate materially as a result of changes in commodity prices and resulting changes in the fair value of our derivatives.

Derivative instruments expose us to the risk of financial loss in certain 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; or

- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, our derivative arrangements limit the benefit we would otherwise receive from increases in commodity prices. Our decision on the quantity and price at which we choose to hedge our future production, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to hedge future production if the pricing environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program.
We have hedged the majority of our forecasted 2019 natural gas production. Our future crude oil production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.
Our Chairman and Chief Executive Officer beneficially owns approximately 76% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our Company.
As of December 31, 2018, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned approximately 76% of our outstanding common shares. As a result, Mr. Hamm has control over our Company and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. Therefore, Mr. Hamm could cause, delay or prevent a change of control of our Company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.
We have historically entered into, and may enter into, transactions from time to time with companies or persons affiliated with Mr. Hamm if, after an independent review by our Audit Committee or by the independent members of our Board of Directors, it is determined such transactions are in the Company’s best interests and are on terms no less favorable to us than could be achieved with an unaffiliated third party. These transactions may result in conflicts of interest between Mr. Hamm’s affiliated parties and us.
We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.
While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in new or emerging areas are more uncertain than drilling results in developed and producing areas. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage in the emerging areas will decline if drilling results are unsuccessful.
We may be subject to risks in connection with acquisitions, divestitures, and joint development arrangements.
As part of our business strategy, we have made and will likely continue to make acquisitions of oil and gas properties, divest of assets, and enter into joint development arrangements. Suitable acquisition properties, buyers of our assets, or joint development counterparties may not be available on terms and conditions we find acceptable or not at all.
The successful acquisition of producing properties requires an assessment of several factors, including but not limited to:

- recoverable reserves;
- future crude oil and natural gas prices and location and quality differentials;
- the quality of the title to acquired properties;
- future development costs, operating costs and property taxes; and
- potential environmental and other liabilities.

The accuracy of these acquisition assessments is inherently uncertain. In connection with these assessments, we perform a review, which we believe to be generally consistent with industry practices, of the subject properties. 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 prior to acquisition. Inspections may not always be performed on every property, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller of the subject properties may be unwilling or unable to provide effective contractual protection against all or part of the problems. We sometimes are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

In addition, from time to time we may sell or otherwise dispose of certain assets as a result of an evaluation of our asset portfolio or to provide cash flow for use in reducing debt and enhancing liquidity. Such divestitures have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets, and potential post-closing adjustments and claims for indemnification. Additionally, volatility and unpredictability in commodity prices may result in fewer potential bidders, unsuccessful sales efforts, and a higher risk that buyers may seek to terminate a transaction prior to closing. The occurrence of any of the matters described above could have an adverse impact on our business, financial condition, results of operations and cash flows.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities abroad and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that infrastructure we rely on could be a direct target or an indirect casualty of an act of terrorism. Any of these events could materially and adversely affect our business and results of operations.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2018.

Item 2. Properties

The information required by Item 2 is contained in Part I, Item 1. Business—Crude Oil and Natural Gas Operations and is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 11. Commitments and Contingencies–Litigation in Part II, Item 8. Financial Statements and Supplementary Data–Notes to Consolidated Financial Statements for a discussion of the legal matter involving the Company, Billy J. Strack and Daniela A. Renner, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange and trades under the symbol “CLR.” As of January 31, 2019, the number of record holders of our common stock was 1,234. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 71,370. On January 31, 2019, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $46.17 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2018:

Period	Total number of shares purchased (1)	Average price paid per share (2)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
October 1, 2018 to October 31, 2018	785	$ 52.68	—	—
November 1, 2018 to November 30, 2018	11,389	$ 48.00	—	—
December 1, 2018 to December 31, 2018	—	—	—	—
Total	12,174	$ 48.30	—	—

(1) In connection with restricted stock grants under the Company’s 2013 Long-Term Incentive Plan (“2013 Plan”), we adopted a policy that enables employees to surrender shares to cover their tax liability. Shares indicated as having been purchased in the table above represent shares surrendered by employees to cover tax liabilities. We paid the associated taxes to the applicable taxing authorities.

(2) The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2018 relating to equity compensation plans:

	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	13,736,734
Equity Compensation Plans Not Approved by Shareholders	—	—	—

(1) Represents the remaining shares available for issuance under the 2013 Plan.

Performance Graph

The following graph compares our common stock performance with the performance of the Standard & Poor's 500 Stock Index ("S&P 500 Index") and the Dow Jones US Oil and Gas Index ("Dow Jones US O&G Index") for the period of December 31, 2013 through December 31, 2018. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2013 and that any dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

Item 6. Selected Financial Data

This section presents selected consolidated financial data for the years ended December 31, 2014 through 2018. The selected financial data presented below is not intended to replace our consolidated financial statements.

The following financial data has been derived from our audited consolidated financial statements for such periods. You should read the following selected financial data in connection with Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included elsewhere in this report. The selected consolidated results are not necessarily indicative of results to be expected in future periods. Operating and financial results attributable to noncontrolling interests are immaterial and are not separately presented below.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales (1)	$4,678,722	$2,982,966	$2,026,958	$2,552,531	$4,203,022
Gain (loss) on crude oil and natural gas derivatives, net (2)	(23,930)	91,647	(71,859)	91,085	559,759
Total revenues	4,709,586	3,120,828	1,980,273	2,680,167	4,801,618
Net income (loss) (3)	989,700	789,447	(399,679)	(353,668)	977,341
Net income (loss) attributable to Continental Resources (3)(4)	988,317	789,447	(399,679)	(353,668)	977,341
Net income (loss) per share attributable to Continental Resources: (3)(4)					
Basic	$2.66	$2.13	$(1.08)	$(0.96)	$2.65
Diluted	$2.64	$2.11	$(1.08)	$(0.96)	$2.64
Production volumes					
Crude oil (MBbl)	61,384	50,536	46,850	53,517	44,530
Natural gas (MMcf)	284,730	228,159	195,240	164,454	114,295
Crude oil equivalents (MBoe)	108,839	88,562	79,390	80,926	63,579
Average costs per unit					
Production expenses ($/Boe)	$3.59	$3.66	$3.65	$4.30	$5.58
Production taxes (% of net oil and gas revenues)	7.9%	7.0%	7.0%	7.8%	8.2%
DD&A ($/Boe)	$17.09	$18.89	$21.54	$21.57	$21.51
General and administrative expenses ($/Boe)	$1.69	$2.16	$2.14	$2.34	$2.92
Proved reserves at December 31					
Crude oil (MBbl)	757,096	640,949	643,228	700,514	866,360
Natural gas (MMcf)	4,591,614	4,140,281	3,789,818	3,151,786	2,908,386
Crude oil equivalents (MBoe)	1,522,365	1,330,995	1,274,864	1,225,811	1,351,091
Other financial data (in thousands)					
Net cash provided by operating activities	$3,456,008	$2,079,106	$1,125,919	$1,857,101	$3,355,715
Net cash used in investing activities	$(2,860,172)	$(1,808,845)	$(532,965)	$(3,046,247)	$(4,587,399)
Net cash (used in) provided by financing activities	$(356,934)	$(243,034)	$(587,773)	$1,187,189	$1,227,715
Total capital expenditures	$2,928,746	$2,035,254	$1,110,256	$2,564,301	$5,015,595
Balance Sheet data at December 31 (in thousands)					

Total assets	$15,297,947	$14,199,651	$13,811,776	$14,919,808	$15,076,033
Long-term debt, including current portion	$5,768,349	$6,353,691	$6,579,916	$7,117,788	$5,928,878
Total equity	$6,421,861	$5,131,203	$4,301,996	$4,668,900	$4,967,844

(1) In years prior to 2018, we generally presented our revenues net of costs incurred to transport our production to market. For 2018, crude oil and natural gas sales are presented gross of certain transportation expenses as a result of our January 1, 2018 adoption of new revenue recognition and presentation rules as discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues. We adopted the new rules using a modified retrospective transition approach whereby the rules were prospectively applied beginning January 1, 2018 and prior period results have not been adjusted to conform to the current presentation. The change in presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on our results of operations, net income, or cash flows for 2018.

(2) Crude oil and natural gas derivative instruments are not designated as hedges for accounting purposes and, therefore, changes in the fair value of the instruments are shown separately from crude oil and natural gas sales. The year 2014 includes $433 million of gains recognized from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities initially scheduled through December 2016.

(3) Results for 2017 reflect the remeasurement of the Company's deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share). See Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Income

Taxes for further discussion. Additionally, 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Commitments and Contingencies, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

(4) Excludes results attributable to noncontrolling interests. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests for a discussion of new arrangements executed in 2018 that gave rise to the separate presentation of results attributable to Continental and noncontrolling interests in our financial statements.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes, as well as the selected consolidated financial data included elsewhere in this report. Our operating results for the periods discussed below may not be indicative of future performance. Results attributable to noncontrolling interests are immaterial and are not separately presented or discussed below.

For additional discussion of crude oil and natural gas reserve information, please see Part I, Item 1. Business—Crude Oil and Natural Gas Operations. The following discussion and analysis includes forward-looking statements and should be read in conjunction with Part I, Item 1A. Risk Factors in this report, along with Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995 at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development and production of crude oil and natural gas. Additionally, we pursue the acquisition and management of perpetually owned minerals located in certain of our key operating areas. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas and expect this to continue in the future. Our operations are primarily focused on exploration and development activities in the Bakken field of North Dakota and Montana and the SCOOP and STACK areas of Oklahoma. Our common stock trades on the New York Stock Exchange under the symbol "CLR" and our corporate internet website is www.clr.com.

2018 Highlights

Production

Crude oil and natural gas production averaged 298,190 Boe per day in 2018, an increase of 23% compared to 2017. Total production for the fourth quarter of 2018 averaged 324,001 Boe per day, an increase of 9% compared to the third quarter of 2018 and 13% higher than the fourth quarter of 2017.

Average daily crude oil production increased 21% in 2018 compared to 2017 while average daily natural gas production increased 25%.

The following table summarizes the changes in our average daily Boe production by major operating area for the periods presented.

	Fourth Quarter			Year Ended December 31,		
Boe production per day	2018	2017	% Change	2018	2017	% Change
Bakken	183,836	165,598	11 %	167,800	132,992	26 %
SCOOP	67,244	62,242	8 %	64,339	60,693	6 %
STACK	62,947	47,914	31 %	56,055	36,220	55 %
All other	9,974	11,231	(11 %)	9,996	12,732	(21 %)
Total	324,001	286,985	13 %	298,190	242,637	23 %

Proved reserves

At December 31, 2018, our proved reserves totaled 1,522 MMBoe, an increase of 14% from proved reserves of 1,331 MMBoe at December 31, 2017.

Extensions, discoveries and other additions from our drilling and completion activities added 565 MMBoe of proved reserves in 2018 and upward reserve revisions due to improved commodity prices increased reserves by 26 MMBoe. These increases were partially offset by 109 MMBoe of production during the year and net downward reserve revisions and removals totaling 295 MMBoe resulting from changes in drilling plans and other factors.

The following table summarizes the changes in our proved reserves by major operating area in 2018:

Proved reserves by area	December 31, 2018 MBoe	Percent	December 31, 2017 MBoe	Percent	Volume change	Volume percent change
Bakken	798,005	52 %	635,521	48 %	162,484	26 %
SCOOP	459,103	30 %	491,776	37 %	(32,673)	(7 %)
STACK	230,175	15 %	167,390	13 %	62,785	38 %
All Other	35,082	3 %	36,308	2 %	(1,226)	(3 %)
Total	1,522,365	100 %	1,330,995	100 %	191,370	14 %

Operating cash flows

Net cash inflows from operating activities totaled $3.46 billion for 2018, an increase of 66% compared to $2.08 billion for 2017, reflecting higher commodity prices and sales volumes. Net cash inflows from operating activities exceeded net cash outflows from investing activities by $596 million for 2018, allowing for further debt reduction during the year.

Debt and liquidity

Total debt decreased $585 million, or 9%, in 2018, reflecting the repayment of all previously outstanding credit facility borrowings at year-end 2017 along with the $400 million partial redemption of our $2.0 billion of 5% Senior Notes due 2022 in August 2018.

At December 31, 2018, we had $283 million of cash and cash equivalents and $1.5 billion of borrowing availability on our credit facility. We had no outstanding credit facility borrowings at December 31, 2018 and continued to have no outstanding borrowings as of January 31, 2019.

Strategic mineral relationship

In October 2018 we entered into a strategic relationship with Franco-Nevada Corporation to acquire oil and gas mineral interests in the SCOOP and STACK plays through a newly-formed minerals subsidiary. At closing, Franco-Nevada paid $214.8 million to Continental for an interest in the minerals subsidiary and for funding of its share of certain mineral acquisition costs, and has subsequently made additional funding contributions. Under the arrangement, Continental is to fund 20% of future mineral acquisitions and will be entitled to receive between 25% and 50% of total revenues generated by the minerals subsidiary based upon performance relative to predetermined production targets. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests for additional information.

Financial and operating highlights

We use a variety of financial and operating measures to assess our performance. Among these measures are:

- Volumes of crude oil and natural gas produced;
- Crude oil and natural gas price differentials relative to NYMEX benchmark prices; and
- Per unit operating and administrative costs.

The following table contains financial and operating highlights for the periods presented. Average net sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

	Year ended December 31,		
	2018	2017	2016
Average daily production:			
Crude oil (Bbl per day)	168,177	138,455	128,005
Natural gas (Mcf per day)	780,083	625,093	533,442
Crude oil equivalents (Boe per day)	298,190	242,637	216,912
Average net sales prices: (1)			
Crude oil ($/Bbl)	$59.19	$45.70	$35.51
Natural gas ($/Mcf)	$3.01	$2.93	$1.87
Crude oil equivalents ($/Boe)	$41.25	$33.65	$25.55
Crude oil net sales price discount to NYMEX ($/Bbl)	$(5.27)	$(5.50)	$(7.33)
Natural gas net sales price discount to NYMEX ($/Mcf)	$(0.09)	$(0.16)	$(0.61)
Production expenses ($/Boe)	$3.59	$3.66	$3.65
Production taxes (% of net crude oil and natural gas sales)	7.9 %	7.0 %	7.0 %
DD&A ($/Boe)	$17.09	$18.89	$21.54
Total general and administrative expenses ($/Boe)	$1.69	$2.16	$2.14

(1) See the subsequent section titled Non-GAAP Financial Measures for a discussion and calculation of net sales prices, which are non-GAAP measures for 2018.

Results of Operations

The following table presents selected financial and operating information for the periods presented.

In thousands, except sales price data	Year Ended December 31, 2018	2017	2016
Crude oil and natural gas sales (1)	$ 4,678,722	$ 2,982,966	$ 2,026,958
Gain (loss) on crude oil and natural gas derivatives, net	(23,930)	91,647	(71,859)
Crude oil and natural gas service operations	54,794	46,215	25,174
Total revenues	4,709,586	3,120,828	1,980,273
Operating costs and expenses (2)	(3,115,866)	(2,671,427)	(2,267,807)
Other expenses, net (3)	(296,918)	(293,334)	(344,920)
Income (loss) before income taxes	1,296,802	156,067	(632,454)
(Provision) benefit for income taxes (4)	(307,102)	633,380	232,775
Net income (loss)	989,700	789,447	(399,679)
Net income attributable to noncontrolling interests	1,383	—	—
Net income (loss) attributable to Continental Resources	$ 988,317	$ 789,447	$ (399,679)
Diluted net income (loss) per share attributable to Continental Resources	$ 2.64	$ 2.11	$ (1.08)
Production volumes:			
Crude oil (MBbl)	61,384	50,536	46,850
Natural gas (MMcf)	284,730	228,159	195,240
Crude oil equivalents (MBoe)	108,839	88,562	79,390
Sales volumes:			
Crude oil (MBbl)	61,332	50,628	46,802
Natural gas (MMcf)	284,730	228,159	195,240
	108,787	88,655	79,342

Crude oil
equivalents (MBoe)

(1) In years prior to 2018, we generally presented our revenues net of costs incurred to transport our production to market. For 2018, crude oil and natural gas sales are presented gross of certain transportation expenses as a result of our January 1, 2018 adoption of new revenue recognition and presentation rules (ASU 2016-08) as discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues. We adopted the new rules using a modified retrospective transition approach whereby the rules were prospectively applied beginning January 1, 2018 and prior period results have not been adjusted to conform to the current presentation. The change in presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on our results of operations, net income, or cash flows for 2018.

(2) Net of gain on sale of assets of $16.7 million, $55.1 million, and $304.5 million for 2018, 2017, and 2016, respectively. The year 2018 includes $191.6 million of transportation expenses that are presented gross of crude oil and natural gas sales as a result of our aforementioned adoption of ASU 2016-08 on January 1, 2018. The year 2017 includes a $59.6 million loss accrual recognized in conjunction with the litigation settlement described in Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Commitments and Contingencies—Litigation.

(3) Includes losses on extinguishment of debt of $7.1 million, $0.6 million, and $26.1 million for 2018, 2017, and 2016, respectively.

(4) The year 2017 reflects the remeasurement of our deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time decrease in income tax expense via the recognition of an income tax benefit totaling $713.7 million.

Year ended December 31, 2018 compared to the year ended December 31, 2017

Production

The following tables reflect our production by product and region for the periods presented.

	Year Ended December 31,								Volume increase	Volume percent increase	
	2018			2017							
	Volume	Percent		Volume	Percent						
Crude oil (MBbl)	61,384	56	%	50,536	57	%			10,848	21	%
Natural gas (MMcf)	284,730	44	%	228,159	43	%			56,571	25	%
Total (MBoe)	108,839	100	%	88,562	100	%			20,277	23	%

	Year Ended December 31,						Volume increase	Volume percent increase	
	2018			2017					
	MBoe	Percent		MBoe	Percent				
North Region	64,577	59	%	52,258	59	%	12,319	24	%
South Region	44,262	41	%	36,304	41	%	7,958	22	%
Total	108,839	100	%	88,562	100	%	20,277	23	%

The 21% increase in crude oil production in 2018 compared to 2017 was primarily due to a 9,811 MBbls, or 27%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities and improved initial production results achieved on new wells resulting from optimized completion technologies. Additionally, crude oil production from the STACK and SCOOP plays increased 416 MBbls (up 13%) and 1,192 MBbls (up 21%), respectively, from the prior year due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in those areas. These increases were partially offset by decreased production from our North region properties in Montana Bakken and the Red River units due to natural declines in production. Montana Bakken crude oil production decreased 281 MBbls, or 13%, while crude oil production in the Red River units decreased 261 MBbls, or 8%, from the prior year.

The 25% increase in natural gas production in 2018 compared to 2017 was primarily due to increased production from our properties in the STACK play due to additional wells being completed. Natural gas production in STACK increased 40,942 MMcf, or 68%, over the prior year. Additionally, natural gas production in North Dakota Bakken increased 19,216 MMcf, or 32%, in conjunction with the aforementioned increase in crude oil production over the prior year. Increased drilling and completion activities in the SCOOP play contributed to an 834 MMcf, or 1%, increase in natural gas production compared to the prior year. These increases were partially offset by reduced production from various other areas due to property dispositions and natural declines in production.

Crude oil represented 58% of our production for the fourth quarter of 2018 compared to 55% for the third quarter of 2018, reflecting increased well completion activities on oil-weighted properties in the fourth quarter. We expect continued growth of oil-weighted production in 2019.

Revenues

Our revenues consist of sales of crude oil and natural gas, gains and losses resulting from changes in the fair value of our natural gas derivative instruments, and revenues associated with crude oil and natural gas service operations.

Net crude oil and natural gas sales and related net sales prices presented below are non-GAAP measures for 2018. See the subsequent section titled Non-GAAP Financial Measures for discussion and calculation of these measures.

Net crude oil and natural gas sales. Net crude oil and natural gas sales for 2018 were $4.49 billion, a 50% increase from sales of $2.98 billion for 2017 due to increases in sales volumes and net sales prices as described below.

Total sales volumes for 2018 increased 20,132 MBoe, or 23%, compared to 2017, reflecting an increase in our pace of drilling and completion activities in 2018. For 2018, our crude oil sales volumes increased 21% compared to 2017 while our natural gas sales volumes increased 25%.

Our crude oil net sales prices averaged $59.19 per barrel for 2018, an increase of 30% compared to $45.70 for 2017 due to higher crude oil market prices and improved price realizations. The differential between NYMEX West Texas Intermediate (“WTI”) calendar month crude oil prices and our realized crude oil net sales prices averaged $5.27 per barrel for 2018 compared to $5.50 for 2017. The improved differential was due in part to the amendment of an existing third party transportation arrangement for North region production that resulted in lower per-barrel fees charged to the Company, effective January 1, 2018, along with growth in our South region crude oil production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma. The positive impact from these factors was partially offset by a significant widening of our oil differentials in late 2018 due to heavier than normal refinery maintenance and other factors that adversely impacted our price realizations in the Bakken, causing our crude oil differential to increase to $8.44 per barrel for the 2018 fourth quarter compared to $3.72 per barrel for the 2018 third quarter. The factors contributing to wider differentials in late 2018 have improved and we currently expect our crude oil differentials will strengthen in 2019 compared to 2018 fourth quarter levels.

Our natural gas net sales prices averaged $3.01 per Mcf for 2018, a 3% increase compared to $2.93 per Mcf for 2017 due to improved price realizations for our natural gas sales stream. The discount between our realized natural gas net sales prices and NYMEX Henry Hub calendar month natural gas prices averaged $0.09 per Mcf for 2018 compared to $0.16 per Mcf for 2017. We sell the majority of our operated natural gas production to midstream customers at lease locations under multi-year term contracts based on market prices in the field where the sales occur. The field markets are impacted by residue gas and natural gas liquids ("NGLs") prices at secondary, downstream markets. For the first nine months of 2018, NGL prices were generally higher than 2017 levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream relative to benchmark prices. However, NGL prices decreased in late 2018 in conjunction with the significant decrease in crude oil prices described below, which adversely impacted the price realizations for our natural gas sales stream and caused our differential to Henry Hub benchmark prices to be a discount of $0.40 per Mcf for the 2018 fourth quarter compared to a premium of $0.22 per Mcf for the 2018 third quarter.

For the 2018 fourth quarter, net crude oil and natural gas sales totaled $1.11 billion, a 10% decrease from the 2018 third quarter and a 9% increase from the 2017 fourth quarter. Revenues for the 2018 fourth quarter were adversely impacted by a significant decrease in WTI benchmark prices, which decreased 42% during the quarter from a high of $76.40 per barrel to a low of $44.48 per barrel. Our crude oil net sales prices averaged $50.06 per barrel in the 2018 fourth quarter compared to $65.78 for the 2018 third quarter and $51.16 for the 2017 fourth quarter. The reduction in our fourth quarter sales from lower crude oil prices was mitigated by increased sales volumes. Crude oil sales volumes for the 2018 fourth quarter increased 13% and 10% compared to the 2018 third quarter and 2017 fourth quarter periods, respectively, while natural gas sales volumes for the 2018 fourth quarter were 4% and 15% higher than the 2018 third quarter and 2017 fourth quarter periods, respectively.

Derivatives. Changes in natural gas prices during 2018 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $23.9 million for the year, representing $36.9 million of cash losses partially offset by $13.0 million of non-cash gains.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of crude oil reclaimed from waste products. Revenues associated with such activities increased $8.6 million, or 19%, from $46.2 million for 2017 to $54.8 million for 2018 due to an increase in the magnitude of water handling and recycling activities compared to the prior year. The increased activities also resulted in a corresponding increase in service-related expenses compared to 2017.

Operating Costs and Expenses

Production expenses. Production expenses increased $66.2 million, or 20%, from $324.2 million for 2017 to $390.4 million for 2018 primarily due to an increase in the number of producing wells and related 23% increase in sales volumes. Production expenses on a per-Boe basis decreased to $3.59 for 2018 compared to $3.66 for 2017.

Production taxes. Production taxes increased $144.8 million, or 70%, to $353.1 million in 2018 compared to $208.3 million in 2017 primarily due to higher crude oil and natural gas sales. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of net crude oil and natural gas sales averaged 7.9% for 2018 compared to 7.0% for 2017. This increase was due in part to a significant increase in production and revenues generated in North Dakota from increased well completion activities over the past year, which has higher production tax rates compared to Oklahoma. Additionally, in 2017 legislation was enacted in Oklahoma that increased the production tax rate from 4% to 7% (effective December 1, 2017) on wells that began producing between July 1, 2011 and July 1, 2015, which contributed to the increase in our average production tax rate for 2018. In March 2018, new legislation was enacted again in Oklahoma that increased the state's production tax rate, effective July 1, 2018, from 2% to 5% for the first 36 months of production for wells commencing production after July 1, 2015, which also contributed to the increase in our average production tax rate.

Exploration expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods presented.

	Year ended December 31,	
In thousands	2018	2017
Geological and geophysical costs	$7,495	$12,217
Exploratory dry hole costs	147	176
Exploration expenses	$7,642	$12,393

The decrease in geological and geophysical expenses in 2018 was due to changes in the timing and amount of costs incurred by the Company and billed to joint interest owners between periods.

Depreciation, depletion, amortization and accretion (“DD&A”). Total DD&A increased $184.4 million, or 11%, to $1.86 billion for 2018 compared to $1.67 billion for 2017 due to an increase in total sales volumes which was partially offset by the impact from an increase in the volume of proved developed reserves over which costs are depleted as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Year ended December 31,	
$/Boe	2018	2017
Crude oil and natural gas properties	$16.84	$18.57
Other equipment	0.18	0.25
Asset retirement obligation accretion	0.07	0.07
Depreciation, depletion, amortization and accretion	$17.09	$18.89

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense increases. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense decreases. Upward revisions to proved developed reserves over the past year due in part to an improvement in commodity prices contributed to a decrease in our DD&A rate for crude oil and natural gas properties in 2018 compared to 2017. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in an improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in the current period.

Property impairments. Property impairments decreased $112.2 million, or 47%, to $125.2 million in 2018 compared to $237.4 million in 2017, reflecting lower proved and unproved property impairments as described below.

Proved property impairments decreased to $18.0 million for 2018 compared to $82.3 million for 2017 due to changes in commodity prices and resulting impact on fair value assessments and impairments between periods.

Impairments of unproved properties decreased $47.8 million, or 31%, to $107.2 million in 2018 compared to $155.0 million for 2017. This decrease was due to a lower balance of unamortized leasehold costs in the current period and a reduction over the past year in the Company's estimates of undeveloped properties not expected to be developed prior to lease expiration due to an increase in the allocation of capital to development drilling activities in 2017 and 2018.

General and administrative ("G&A") expenses. Total G&A expenses decreased $8.1 million, or 4%, to $183.6 million in 2018 from $191.7 million in 2017. Total G&A expenses include non-cash charges for equity compensation of $47.2 million and $45.9 million for 2018 and 2017, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $136.4 million for 2018, a decrease of $9.4 million, or 6%, compared to $145.8 million for 2017. We incurred higher personnel-related costs in 2018 associated with the growth in our operations over the past year; however, the increased costs were more than offset by operational efficiencies and higher overhead recoveries from joint interest owners due to increased drilling and completion activities.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

$/Boe	Year ended December 31, 2018	2017
General and administrative expenses	$1.25	$1.64
Non-cash equity compensation	0.44	0.52
Total general and administrative expenses	$1.69	$2.16

The decreases in G&A expenses on a per-Boe basis in 2018 were due to a 23% increase in total sales volumes from new well completions with no comparable increase in G&A expenses.
Interest expense. Interest expense decreased to $293.0 million in 2018 compared to $294.5 million in 2017. We incurred lower interest expenses in 2018 resulting from a decrease in total outstanding debt, the impact of which was nearly offset by higher expenses incurred due to increases in market interest rates on variable-rate credit facility borrowings over the past year. Our weighted average outstanding long-term debt balance for 2018 was approximately $6.2 billion with a weighted average interest rate of 4.5% compared to averages of $6.7 billion and 4.2% for 2017. The 2018 period includes $13 million of interest expense associated with the $400 million portion of our 2022 Notes that was redeemed in August 2018.
Income Taxes. For 2018 and 2017 we provided for income taxes at a combined federal and state tax rate of 24.5% and 38%, respectively, of pre-tax income generated by our operations in the United States. Our tax provision for 2018 reflects our application of the Tax Cuts and Jobs Act that was signed into law in December 2017, which among other things reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. The application of statutory tax rates to pre-tax earnings, combined with the impact of permanent taxable differences, valuation allowances, tax effects from stock-based compensation, and other items resulted in the recognition of $307.1 million and $80.3 million of income tax expense for 2018 and 2017, respectively.
Additionally, at year-end 2017 we remeasured our deferred income tax balances in response to the enactment of the Tax Cuts and Jobs Act, which resulted in a one-time decrease in income tax expense in 2017 via the recognition of an income tax benefit totaling $713.7 million and caused a significant inconsistency in the relationship between income tax expense/benefit and pre-tax income. Upon combining the tax benefit from this remeasurement with the tax provision recognized on pre-tax earnings from operations, we recognized a net total income tax benefit of $633.4 million for 2017.
See Part II, Item 8. Notes to Consolidated Financial Statements—Note 9. Income Taxes for a summary of the sources and tax effects of items comprising our income tax provision/benefit and resulting effective tax rates for 2018 and 2017.
Year ended December 31, 2017 compared to the year ended December 31, 2016
Production
The following tables reflect our production by product and region for the periods presented.

	Year Ended December 31,						Volume increase	Volume percent increase	
	2017			2016					
	Volume	Percent		Volume	Percent				
Crude oil (MBbl)	50,536	57	%	46,850	59	%	3,686	8	%
Natural gas (MMcf)	228,159	43	%	195,240	41	%	32,919	17	%
Total (MBoe)	88,562	100	%	79,390	100	%	9,172	12	%

	Year Ended December 31,						Volume increase	Volume percent increase	
	2017			2016					
	MBoe	Percent		MBoe	Percent				
North Region	52,258	59	%	48,169	61	%	4,089	8	%
South Region	36,304	41	%	31,221	39	%	5,083	16	%
Total	88,562	100	%	79,390	100	%	9,172	12	%

The 8% increase in crude oil production in 2017 compared to 2016 was primarily due to a 4,241 MBbls, or 13%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities, the timing of production commencing from new pad development projects, and strong initial production results being achieved on new wells resulting from optimized completion technologies. Additionally, production from our South region properties in the STACK play increased 1,614 MBbls, or 104%, from 2016 due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in that area. These increases were partially offset by decreased production from our North region properties in Montana Bakken and the Red River units due to natural declines in production coupled with reduced drilling activities. Montana Bakken crude oil production decreased 692 MBbls, or 24%, while crude oil production in the Red River units decreased 344 MBbls, or 9%, compared to 2016. Additionally, crude oil production in SCOOP decreased 1,081 MBbls, or 16%, due to natural declines in production and limited drilling activities.

The 17% increase in natural gas production in 2017 compared to 2016 was primarily due to increased production from our properties in the STACK play due to additional wells being completed and producing. Natural gas production in STACK increased 32,342 MMcf, or 116%, compared to 2016. Additionally, natural gas production in North Dakota Bakken increased 8,700 MMcf, or 17%, in conjunction with the aforementioned increase in crude oil production. These increases were partially offset by reduced production from our SCOOP properties, which decreased 3,469 MMcf, or 3%, along with various other areas in our North and South regions due to natural declines in production and limited drilling activities. Further, natural gas production decreased 1,323 MMcf in 2017 as a result of the sale of substantially all of our Arkoma Woodford properties in September 2017.

The increase in natural gas production as a percentage of our total production from 41% in 2016 to 43% in 2017 primarily resulted from the significant increase in STACK natural gas production due to the increased allocation of capital to that area in 2017.

Revenues

Net crude oil and natural gas sales. Net crude oil and natural gas sales for 2017 were $2.98 billion, a 47% increase from sales of $2.03 billion for 2016 due to a 32% increase in realized commodity prices coupled with a 12% increase in total sales volumes.

Our crude oil net sales prices averaged $45.70 per barrel for 2017, an increase of 29% compared to $35.51 for 2016 due to higher crude oil market prices and improved price realizations. The differential between NYMEX WTI calendar month crude oil prices and our realized crude oil prices averaged $5.50 per barrel for 2017 compared to $7.33 for 2016. The improved differential was primarily due to improved realizations resulting from new pipeline takeaway capacity and additional markets becoming available in 2017 for Bakken production, along with the growth in our South region production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma. These factors led to a continued improvement in crude oil price realizations throughout 2017. Our crude oil price differentials relative to WTI prices improved to $4.23 per barrel in the 2017 fourth quarter.

Our natural gas net sales prices averaged $2.93 per Mcf for 2017, a 57% increase compared to $1.87 per Mcf for 2016 due to higher market prices for natural gas and NGLs and improved price realizations. The discount between our realized natural gas net sales prices and NYMEX Henry Hub calendar month natural gas prices improved from $0.61 per Mcf for 2016 to $0.16 per Mcf for 2017. NGL prices increased over 2016 levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream, particularly in later months of 2017. Our realized natural gas net sales prices averaged $3.30 per Mcf in the 2017 fourth quarter, representing a premium of $0.37 per Mcf over Henry Hub benchmark prices for that period.

Total sales volumes for 2017 increased 9,313 MBoe, or 12%, compared to 2016, reflecting an increase in our pace of drilling and completion activities in 2017. For 2017, our crude oil sales volumes increased 8% compared to 2016 while our natural gas sales volumes increased 17%.

For the 2017 fourth quarter, net crude oil and natural gas sales totaled $1,017.7 million, representing a 44% increase from 2017 third quarter revenues of $704.8 million and a 72% increase from 2016 fourth quarter revenues of $591.8 million. Revenues for the 2017 fourth quarter were favorably impacted by improved commodity prices and price realizations late in the year. Our crude oil net sales prices averaged $51.16 per barrel in the 2017 fourth quarter compared to $43.27 for the 2017 third quarter and $42.23 for the 2016 fourth quarter. Our natural gas net sales prices averaged $3.30 per Mcf in the 2017 fourth quarter compared to $2.74 for the 2017 third quarter and $2.70 for the 2016 fourth quarter.

Derivatives. Changes in natural gas prices during 2017 had an overall favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $91.6 million for the year, representing $62.1 million of non-cash gains and $29.5 million of cash gains.

Crude oil and natural gas service operations. Revenues associated with our crude oil and natural gas service operations increased $21.0 million, or 84%, from $25.2 million for 2016 to $46.2 million for 2017 due to an increase in industry production activities and changes in the nature, timing and extent of water handling and recycling activities between periods.

Operating Costs and Expenses

Production expenses. Production expenses increased $34.9 million, or 12%, from $289.3 million for 2016 to $324.2 million for 2017 due to an increase in the number of producing wells and higher workover-related activities aimed at enhancing production from producing properties. Production expenses on a per-Boe basis averaged $3.66 for 2017, consistent with $3.65 per Boe for 2016. Our per-unit production expenses decreased to $3.17 per Boe for the 2017 fourth quarter.

Production taxes. Production taxes increased $65.9 million, or 46%, to $208.3 million in 2017 compared to $142.4 million in 2016 due to higher crude oil and natural gas revenues resulting from increases in sales volumes and commodity prices over the prior year period. Production taxes as a percentage of net crude oil and natural gas sales averaged 7.0% for 2017, consistent with the 2016 average of 7.0%.

Our production tax rate increased in the second half of 2017 relative to the first half and averaged 7.3% for the 2017 fourth quarter. This increase primarily resulted from a significant increase in production and revenues being generated in North Dakota from increased well completions later in 2017, which has higher production tax rates compared to Oklahoma. Additionally, in 2017 new legislation was enacted in Oklahoma that increased the production tax rate from 1% to 4%, effective July 1, 2017, and again from 4% to 7%, effective December 1, 2017, on wells that began producing between July 1, 2011 and July 1, 2015, which contributed to an increase in our average production tax rate in the third and fourth quarters of 2017.

Exploration expenses. The following table shows the components of exploration expenses for the periods presented.

	Year ended December 31,	
In thousands	2017	2016
Geological and geophysical costs	$12,217	$12,106
Exploratory dry hole costs	176	4,866
Exploration expenses	$12,393	$16,972

Depreciation, depletion, amortization and accretion. Total DD&A decreased $33.8 million, or 2%, to $1.67 billion for 2017 compared to $1.71 billion for 2016 primarily due to an increase in the volume of proved developed reserves over which costs are depleted, the impact of which was partially offset by an increase in DD&A resulting from higher sales volumes in 2017. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Year ended December 31,	
$/Boe	2017	2016
Crude oil and natural gas properties	$18.57	$21.09
Other equipment	0.25	0.37
Asset retirement obligation accretion	0.07	0.08
Depreciation, depletion, amortization and accretion	$18.89	$21.54

Upward revisions to proved developed reserves in 2017 due in part to an improvement in commodity prices contributed to a decrease in our DD&A rate for crude oil and natural gas properties in 2017 compared to 2016. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in a significant improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in 2017.

Property impairments. Property impairments totaled $237.4 million for 2017, consistent with $237.3 million of impairments recognized in 2016. Higher proved property impairments in 2017 were offset by lower unproved property impairments as discussed below.

Proved property impairments totaled $82.3 million for 2017 compared to $2.9 million for 2016. The proved property impairments recognized in 2017, nearly all of which were recognized in the second quarter, were primarily concentrated in the Arkoma Woodford field for which we determined the carrying amount of the field was not recoverable from future cash flows and, therefore, was impaired at June 30, 2017.

Impairments of unproved properties decreased $79.4 million, or 34%, to $155.0 million in 2017 compared to $234.4 million for 2016. The decrease was due to a lower balance of unamortized leasehold costs in 2017 due to property dispositions and reduced land capital expenditures in recent years, along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company’s estimates of undeveloped properties not expected to be developed before lease expiration.

General and administrative expenses. Total G&A expenses increased $22.1 million, or 13%, to $191.7 million in 2017 from $169.6 million in 2016. Total G&A expenses include non-cash charges for equity compensation of $45.9 million and $48.1 million for 2017 and 2016, respectively, the decrease of which resulted from changes in the timing and magnitude of forfeitures of unvested restricted stock between periods.

G&A expenses other than equity compensation included in the total G&A expense figure above totaled $145.8 million for 2017, an increase of $24.3 million, or 20%, compared to $121.5 million for 2016. This increase was primarily due to an increase in employee compensation and benefits in 2017 in response to the stabilization and improvement in commodity prices over the past year, partially offset by higher overhead recoveries from joint interest owners due to increased completion activities over the prior period.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

	Year ended December 31,	
$/Boe	2017	2016
General and administrative expenses	$1.64	$1.53
Non-cash equity compensation	0.52	0.61
Total general and administrative expenses	$2.16	$2.14

Interest expense. Interest expense decreased $26.1 million, or 8%, to $294.5 million in 2017 from $320.6 million in 2016 due to a decrease in weighted average outstanding debt primarily as a result of the November 2016 redemptions of our $200 million of 7.375% 2020 Notes and $400 million of 7.125% 2021 Notes. Our weighted average outstanding long-term debt balance for 2017 was approximately $6.7 billion with a weighted average interest rate of 4.2% compared to averages of $7.1 billion and 4.3% for 2016. The lower interest expense associated with reduced debt was partially offset by higher interest expense being incurred on our variable-rate credit facility and term loan borrowings due to an increase in market interest rates in 2017.

Income Taxes. Our income before income taxes totaled $156.1 million for the year ended December 31, 2017, nearly all of which was generated by our operations in the United States. We provided for income taxes on this amount at a combined federal and state tax rate of 38% of pre-tax income generated in the United States and 25% of immaterial pre-tax losses generated by our operations in Canada. The application of these statutory tax rates to pre-tax earnings, combined with the impact of permanent taxable differences, valuation allowances, tax effects from stock-based compensation, and other items resulted in the recognition of $80.3 million of income tax expense for 2017. Additionally, the aforementioned remeasurement of our deferred income tax balances at year-end 2017 in response to the enactment of the Tax Cuts and Jobs Act resulted in a one-time decrease in income tax expense via the recognition of an income tax benefit totaling approximately $713.7 million. Upon combining the tax benefit from this remeasurement with the tax provision recognized on pre-tax earnings from operations, we recognized a net total income tax benefit of $633.4 million for 2017.

For 2016, we recorded an income tax benefit of $232.8 million, resulting in an effective tax rate of 37% after taking into account the application of a combined statutory tax rate of 38%, permanent taxable differences, tax effects from stock-based compensation, valuation allowances, and other items.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt securities. Additionally, in recent years asset dispositions and joint development arrangements have provided a source of cash flow for use in reducing debt and enhancing liquidity. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from additional potential sales of non-strategic assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

Based on our planned capital spending, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our revolving credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to the various agreements subsequently described under the heading Contractual Obligations, recognizing we may be required to meet such commitments even if our business plan assumptions were to change. We monitor our capital spending closely based on actual and projected cash flows and have the ability to reduce spending or dispose of assets to preserve liquidity and financial flexibility if needed to fund our operations.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities totaled $3.46 billion and $2.08 billion for 2018 and 2017, respectively. The increase in operating cash flows was primarily due to an increase in crude oil and natural gas revenues resulting from higher realized commodity prices and total sales volumes in 2018, the effects of which were partially offset by increases in production expenses, production taxes, and cash losses on matured natural gas derivatives, as well as the litigation settlement payment described in Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Commitments and Contingencies–Litigation.

Cash flows used in investing activities

For 2018 and 2017, we had cash flows used in investing activities of $2.86 billion and $1.81 billion, respectively, the increase of which was due to an increase in our capital budget and related drilling and completion activities in 2018. These totals include cash capital expenditures of $2.91 billion and $1.95 billion, respectively, inclusive of exploration and development drilling, property acquisitions, and leasing activities. Additionally, the 2018 amount includes consolidated mineral acquisitions by our less-than-wholly-owned subsidiary TMRC II, of which 80% was reimbursed to the Company by Franco-Nevada under the new relationship described in Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests.

The use of cash for capital expenditures was partially offset by proceeds received from asset dispositions, which totaled $54.5 million and $144.4 million for 2018 and 2017, respectively. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 16. Property Dispositions for a discussion of notable dispositions.

Cash flows used in financing activities

Net cash used in financing activities for 2018 totaled $356.9 million, primarily resulting from a $585.4 million reduction in total outstanding debt using available cash flows from operations and proceeds from asset dispositions. Cash outflows for debt reduction were partially offset by $267.9 million of contributions received from noncontrolling interests, primarily from Franco-Nevada for its ownership interest in TMRC II and for funding of its share of certain mineral acquisition costs.

Net cash used in financing activities for 2017 totaled $243.0 million, primarily resulting from a reduction in total outstanding debt using available cash flows from operations and proceeds from asset dispositions. We received $990 million of net proceeds from our December 2017 issuance of 4.375% Senior Notes due 2028, which were used to repay in full and terminate our then existing $500 million term loan and to repay a portion of the borrowings then outstanding under our revolving credit facility, thereby resulting in no significant net change in cash flows from financing activities in 2017 related to these activities.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our remaining cash balance and availability under our revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments for at least the next 12 months.

Under the current commodity price environment, our planned capital expenditures for 2019 are expected to be funded entirely from operating cash flows. Additionally, we expect to generate cash flows in excess of operating and capital needs, which we plan to apply toward further reduction of debt in the future.

We currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our revolving credit facility if needed to fund our operations. We may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise. Further, we may sell additional assets or enter into strategic joint development opportunities in order to obtain funding for our operations and capital program if such transactions can be executed on satisfactory terms.

Revolving credit facility

We have an unsecured credit facility, maturing in April 2023, with aggregate lender commitments totaling $1.5 billion. The commitments are from a syndicate of 14 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment.

As of January 31, 2019, we had no outstanding borrowings and approximately $1.5 billion of borrowing availability on our credit facility.

The commitments under our credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating would not trigger a reduction in our current credit facility commitments, nor would such actions trigger a security requirement or change in covenants. Downgrades of our credit rating will, however, trigger increases in our credit facility's interest rates and commitment fees paid on unused borrowing availability under certain circumstances.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt for a discussion of how this ratio is calculated pursuant to our revolving credit agreement.

We were in compliance with our credit facility covenants at December 31, 2018 and expect to maintain compliance for at least the next 12 months. At December 31, 2018, our consolidated net debt to total capitalization ratio was 0.43 to 1.00. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing to a material extent if needed to support our business.

Joint development agreement funding

In September 2014, we entered into an agreement with a U.S. subsidiary of SK E&S Co. Ltd ("SK") of South Korea to jointly develop a portion of the Company's STACK properties. Pursuant to the agreement SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest in the STACK play until approximately $270 million has been expended by SK on our behalf. As of December 31, 2018, approximately $30 million of the carry had yet to be realized and is expected to be realized in 2019.

Strategic mineral relationship

See Part II, Item 8. Notes to Consolidated Financial Statements—Note 15. Noncontrolling Interests for discussion of the capital requirements and future sources of financing associated with our strategic relationship with Franco-Nevada to acquire oil and gas mineral interests in the SCOOP and STACK plays through year-end 2021.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $5.8 billion at December 31, 2018. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt.

In August 2018, we redeemed $400 million of our $2.0 billion of 5% Senior Notes due 2022. Under the current commodity price environment we expect to generate cash flows in excess of operating and capital needs, which we plan to apply toward further redemption of our 2022 Notes in the future, the timing of which is uncertain.

We were in compliance with our senior note covenants at December 31, 2018 and expect to maintain compliance for at least the next 12 months. We do not believe the senior note covenants will materially limit our ability to undertake additional debt financing. Downgrades or other negative rating actions with respect to the credit ratings assigned to our senior unsecured debt would not trigger additional senior note covenants.

Capital expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas.

For the year ended December 31, 2018, we invested $2.8 billion in our capital program, excluding $84.8 million of unbudgeted acquisitions and including $14.7 million of capital costs associated with increased accruals for capital expenditures. Our 2018 capital expenditures were allocated as follows by quarter:

In millions	1Q 2018	2Q 2018	3Q 2018	4Q 2018	Total 2018
Exploration and development	$496.3	$627.9	$633.5	$611.0	$2,368.7
Land costs (1)	67.0	44.9	105.5	59.0	276.4
Capital facilities, workovers and other corporate assets	33.0	41.4	51.8	72.6	198.8
Seismic	—	—	—	—	—
Capital expenditures, excluding acquisitions	$596.3	$714.2	$790.8	$742.6	$2,843.9
Acquisitions of producing properties	2.6	21.5	1.4	6.1	31.6
Acquisitions of non-producing properties (1)	28.0	21.6	2.0	1.6	53.2
Total acquisitions	30.6	43.1	3.4	7.7	84.8
Total capital expenditures	$626.9	$757.3	$794.2	$750.3	$2,928.7

(1) These captions include costs incurred during 2018 to acquire minerals, which, along with minerals acquired prior to 2018, were contributed to our newly-formed subsidiary TMRC II in October 2018 as part of the transaction with Franco-Nevada.

Our capital expenditures budget for 2019 is $2.6 billion, which is expected to be allocated as reflected below. Acquisition expenditures are not budgeted, with the exception of planned levels of spending for mineral acquisitions made in conjunction with our relationship with Franco-Nevada.

In millions	2019 Budget
Exploration and development	$ 2,165
Land costs (1)	205
Capital facilities, workovers and other corporate assets	228
Seismic	2
Total 2019 capital budget	$ 2,600

(1) Includes $125 million of planned spending for mineral acquisitions by TMRC II. With a carry structure in place, Continental will recoup $100 million, or 80%, of such spending from Franco-Nevada.

Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our spending should commodity prices decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at competitive terms.

Contractual Obligations

The following table presents our contractual obligations and commitments on an undiscounted basis as of December 31, 2018.

	Payments due by period				
In thousands	Total	Less than 1 year (2019)	Years 2 and 3 (2020-2021)	Years 4 and 5 (2022-2023)	More than 5 years
Arising from arrangements on the balance sheet:					
Revolving credit facility borrowings	$—	$ —	$—	$—	$—
Senior Notes (1)	5,800,000	—	—	3,100,000	2,700,000
Note payable (2)	7,735	2,360	4,950	425	—
Interest payments and commitment fees (3)	2,136,254	266,762	533,293	417,174	919,025
Asset retirement obligations (4)	141,360	4,374	16,401	2,114	118,471
Litigation settlement (5)	19,753	19,753	—	—	—
Arising from arrangements not on balance sheet: (6)					
Operating leases and other (7)	30,389	9,062	9,040	5,492	6,795
Drilling rig commitments (8)	107,241	106,130	1,111	—	—
Transportation and processing commitments (9)	1,832,002	241,253	527,378	496,969	566,402
Total contractual obligations	$10,074,734	$ 649,694	$1,092,173	$4,022,174	$4,310,693

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2018 and do not reflect any discount or premium at which the senior notes were issued or any debt issuance costs.

(2) Represents future principal payments on a 10-year amortizing note payable secured by the Company’s corporate office building in Oklahoma City, Oklahoma and does not reflect any debt issuance costs. Principal and interest are payable monthly through the loan’s maturity date of February 26, 2022.

(3) Interest payments include scheduled cash interest payments on the senior notes and note payable, as well as estimated commitment fees on unused borrowing availability under our credit facility assuming the $1.5 billion of availability as of December 31, 2018 continues through the April 2023 maturity date of the facility.

(4) Amounts represent estimated discounted costs for future dismantlement and abandonment of our crude oil and natural gas properties. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for additional discussion of our asset retirement obligations.

(5) See Part II, Item 8. Notes to Consolidated Financial Statements—Note 11. Commitments and Contingencies—Litigation for discussion of this litigation settlement obligation.

(6) The commitment amounts included in this section primarily represent costs associated with wells operated by the Company. A portion of these costs will be borne by other interest owners. Due to variations in well ownership, our net share of these costs cannot be determined with certainty.

(7) Amounts primarily represent commitments for electric infrastructure, surface use agreements, office buildings and equipment, communication towers, field equipment, sponsorship agreements, and purchase obligations mainly related to software services. These amounts include minimum payment obligations on enforceable commitments with durations in excess of one year at a discounted present value totaling $6 million that qualify as leases and were recognized on our balance sheet on January 1, 2019 upon adoption of ASU 2016-02, Leases, as discussed in Note 1. Organization and Summary of Significant Accounting Policies–New accounting pronouncements not yet adopted at December 31, 2018–Leases.

(8) Amounts represent operating day-rate commitments under drilling rig contracts with various terms extending to February 2020 to ensure rig availability in our key operating areas. These amounts include minimum payment obligations expected to be incurred in 2019 and 2020 at a discounted present value totaling $13 million that qualify as leases and were recognized on our balance sheet on January 1, 2019 upon adoption of ASU 2016-02.

(9) We have entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. These commitments require us to pay per-unit transportation or

processing charges regardless of the amount of capacity used. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. These commitments do not qualify as leases to be recognized on our balance sheet under ASU 2016-02 beginning January 1, 2019.

Derivative Instruments

Between January 1, 2019 and February 15, 2019 we entered into additional natural gas derivative instruments as summarized below. The hedged volumes reflected below represent an aggregation of multiple contracts that are expected to be realized ratably over the indicated period. These derivative instruments will be settled based upon reported NYMEX Henry Hub settlement prices. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for further discussion of our hedging activities, including a summary of derivative contracts in place as of December 31, 2018.

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
April 2019 - December 2019		
Swaps - Henry Hub	63,250,000	$ 2.83

Critical Accounting Policies and Estimates

Our consolidated financial statements and related footnotes contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, and the disclosure and estimation of contingent assets and liabilities. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies and Note 8. Revenues for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used.

In management's opinion, the most significant reporting areas impacted by management's judgments and estimates are crude oil and natural gas reserve estimations, revenue recognition, the choice of accounting method for crude oil and natural gas activities and derivatives, impairment of assets, income taxes and contingent liabilities. These areas are discussed below. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters and are believed to be reasonable under the circumstances. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from the estimates as additional information becomes known.

Crude Oil and Natural Gas Reserves Estimation and Standardized Measure of Future Cash Flows

Our external independent reserve engineers, Ryder Scott, and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. Even though Ryder Scott and our internal technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Estimates of reserves and their values, future production rates, and future costs and expenses are inherently uncertain for various reasons, including many factors beyond the Company's control. Reserve estimates are updated by us at least semi-annually and take into account recent production levels and other technical information about each of our properties.

Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions or removals of estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, changes in business strategies, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered. For the years ended December 31, 2018, 2017, and 2016, net downward revisions and removals of our proved reserves totaled approximately 269 MMBoe, 82 MMBoe, and 110 MMBoe, respectively. We cannot predict the amounts or timing of future reserve revisions or removals.

Estimates of proved reserves are key components of the Company's most significant financial estimates including the computation of depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense would increase, reducing net income. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense would decrease. Future revisions of reserves may be material and could significantly alter future depreciation, depletion, and amortization expense and may result in material impairments of assets.

At December 31, 2018, our proved reserves totaled 1,522 MMBoe as determined using 12-month average first-day-of-the-month prices of $65.56 per barrel for crude oil and $3.10 per MMBtu for natural gas. Actual future prices may be materially higher or lower than those used in our year-end estimates. NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2019 and February 1, 2019 averaged $50.34 per barrel and $3.03 per MMBtu, respectively.

Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were decreased to $45 per barrel our proved reserves at December 31, 2018 could decrease by approximately 92 MMBoe, or 6%, representing a 5% decrease in proved developed producing reserves averaged with a 7% decrease in PUD reserves. If the decrease in proved reserves under this oil price sensitivity existed throughout 2018, our DD&A expense for 2018 would have increased by an estimated 5%.

Holding all other factors constant, if natural gas prices used in our year-end reserve estimates were decreased to $2.00 per MMBtu our proved reserves at December 31, 2018 could decrease by approximately 31 MMBoe, or 2%, representing a 1% decrease in proved developed producing reserves averaged with a 3% decrease in PUD reserves. If the decrease in proved reserves under this gas price sensitivity existed throughout 2018, our DD&A expense for 2018 would have increased by an estimated 1%.

Our DD&A calculations for oil and gas properties are performed on a field basis and revisions to proved reserves will not necessarily be applied ratably across all fields and may not be applied to some fields at all. Further, reserve revisions in significant fields may individually affect our DD&A rate. As a result, the impact on DD&A expense from revisions in reserves cannot be predicted with certainty and may result in changes in expense that are greater or less than the underlying changes in reserves.

See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, Standardized Measure, and PV-10 Sensitivities for additional proved reserve sensitivities under certain increasing and decreasing commodity price scenarios for crude oil and natural gas.

Revenue Recognition

We derive substantially all of our revenues from the sale of crude oil and natural gas. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues for discussion of our accounting policies governing the recognition and presentation of revenues as well as the impact on our financial statements resulting from the implementation of new revenue recognition rules on January 1, 2018.

Operated crude oil and natural gas revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. For non-operated properties, the Company's proportionate share of production is marketed at the discretion of the operators. Non-operated revenues are recognized by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive.

At the end of each month, to record revenues we estimate the amount of production delivered and sold to customers and the prices at which they were sold. Variances between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received and are reflected in our financial statements as crude oil and natural gas sales. These variances have historically not been material.

For the sale of crude oil and natural gas, we evaluate whether we are the principal, and report revenues on a gross basis (revenues presented separately from associated expenses), or an agent, and report revenues on a net basis. In this assessment, we consider if we obtain control of the products before they are transferred to the customer as well as other indicators. Significant judgment may be required in determining the point in time when control of products transfers to customers.

Successful Efforts Method of Accounting

Our business is subject to accounting rules that are unique to the crude oil and natural gas industry. Two generally accepted methods of accounting for oil and gas activities are available—the successful efforts method and the full cost method. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. We use the successful efforts method of accounting for our oil and gas properties. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for further discussion of the accounting policies applicable to the successful efforts method of accounting.

Derivative Activities

We may utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production and for other purposes. We have elected not to designate any of our price risk management activities as cash flow hedges. As a result, we mark our derivative instruments to fair value and recognize the changes in fair value in current earnings.

In determining the amounts to be recorded for our open derivative contracts, we are required to estimate the fair value of the derivatives. We use an independent third party to provide our derivative valuations. The third party's valuation models for derivative contracts are industry-standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value calculations for collars requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates. See Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk for a discussion of the sensitivity of natural gas derivative fair value calculations to changes in forward natural gas prices.

We validate our derivative valuations through management review and by comparison to our counterparties' valuations for reasonableness. Differences between our fair value calculations and counterparty valuations have historically not been material.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk-adjusted proved reserves. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable.

Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis. If the carrying amount of a field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value using a discounted cash flow model. For producing properties, the impairment evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for crude oil and natural gas, future costs to produce those products, estimates of future crude oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions or removals of crude oil and natural gas reserves. Estimates of anticipated sales prices and recoverable reserves are highly judgmental and are subject to material revision in future periods.

Impairment provisions for proved properties totaled $18.0 million for 2018. Commodity price assumptions used for the year-end December 31, 2018 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2023 and were then escalated at 3% per year thereafter. Holding all other factors constant, as forward commodity prices decrease, our probability for recognizing producing property impairments may increase, or the magnitude of impairments to be recognized may increase. Conversely, as forward commodity prices increase, our probability for recognizing producing property impairments may decrease, or the magnitude of impairments to be recognized may decrease or be eliminated. As of December 31, 2018, the publicly available forward commodity strip prices for the year 2023 used in our fourth quarter impairment calculations averaged $52.34 per barrel for crude oil and $2.71 per Mcf for natural gas. If forward commodity prices materially decrease from current levels for an extended period, additional impairments of producing properties may be recognized in the future. Because of the uncertainty inherent in the numerous factors utilized in determining the fair value of producing properties, we cannot predict the timing and amount of future impairment charges, if any.

Impairment losses for unproved properties are generally recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management. The estimated timing and rate of successful drilling is highly judgmental and is subject to material revision in future periods as better information becomes available.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2018, we believe all deferred tax assets, net of valuation allowances, reflected in our consolidated balance sheets will ultimately be utilized. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly related to prevailing crude oil and natural gas prices). If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not that a deferred tax asset will not be utilized.

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax-paying companies. Our effective tax rate is affected by, among other things, permanent taxable differences, valuation allowances, and changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on current period earnings.

Contingent Liabilities

A provision for legal, environmental and other contingencies is charged to expense when a loss is probable and the loss or range of loss can be reasonably estimated. Determining when liabilities and expenses should be recorded for these contingencies and the appropriate amounts of accruals is subject to an estimation process that requires subjective judgment of management. In certain cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies dealing with similar matters, and management's decision on how it intends to respond to a particular matter; for example, a decision to contest it vigorously or a decision to seek a negotiated settlement. Actual losses can differ from estimates for various reasons, including differing interpretations of laws and opinions and assessments on the amount of damages. We closely monitor known and potential legal, environmental and other contingencies and make our best estimate of when or if to record liabilities and losses for matters based on available information.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resources.

New Accounting Pronouncements

See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for discussions of the new revenue recognition and presentation rules adopted on January 1, 2018, the impact of new lease accounting rules adopted on January 1, 2019, and new guidance on estimating credit losses not yet adopted.

Legislative and Regulatory Developments

The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a discussion of significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.

2017 Tax Reform Legislation

In December 2017, the Tax Cuts and Jobs Act was signed into law which contained several significant changes to U.S. corporate tax laws, including a reduction of the corporate income tax rate from 35% to 21%. The legislation also included a variety of other changes such as the repeal of the alternative minimum tax; the introduction of new limitations on the tax deductibility of net operating losses, interest expenses, and executive compensation expenses; the acceleration of expensing of certain qualified property; and the introduction of new laws governing taxation of foreign earnings of U.S. entities, among other things. Changes arising from the Tax Cuts and Jobs Act generally became effective on January 1, 2018.

The tax law changes are generally expected to have an overall favorable impact on our business primarily due to expected benefits from the reduced corporate tax rate. The law changes are not expected to adversely impact our liquidity or the amount of cash payments we make for income taxes for at least the next five years.
The Company's accounting for the effects of the tax rate change on its deferred tax balances as well as other relevant aspects of the Tax Cuts and Jobs Act was completed as of December 31, 2017 and no provisional amounts were recorded at year-end 2017 that were later adjusted in 2018.

Inflation

Certain drilling and completion costs and costs of oilfield services, equipment, and materials decreased in recent years as service providers reduced their costs in response to reduced demand arising from low crude oil prices. However, inflationary pressures returned in 2017 and increased in 2018 in conjunction with improved crude oil prices. As a result of the low commodity price environment in recent years, the number of providers of services, equipment, and materials decreased in the regions where we operate. If commodity prices show signs of diminished volatility and sustained recovery, industry drilling and completion activities are likely to continue to increase and we may face shortages of service providers, equipment, and materials. Such shortages could result in increased competition which may lead to further increases in costs.

Non-GAAP Financial Measures

Net crude oil and natural gas sales and net sales prices

As discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Revenues, we adopted new revenue recognition and presentation rules on January 1, 2018. The new rules did not have a material impact on the timing of our revenue recognition or our financial position, results of operations, net income, or cash flows for the year ended December 31, 2018, but did impact the presentation of our crude oil and natural gas revenues. We adopted the new rules using a modified retrospective transition approach whereby changes have been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation.
Under the new rules, revenues and transportation expenses associated with production from our operated properties are now reported on a gross basis compared to net presentation in prior years. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice. As a result, beginning January 1, 2018 the gross presentation of revenues from our operated properties differs from the net presentation of revenues from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.
In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results, to achieve comparability between operated and non-operated revenues, and to achieve comparability with prior period metrics for analysis purposes, we have presented crude oil and natural gas sales net of transportation expenses in Management’s Discussion and Analysis of Financial Condition and Results of Operations, which we refer to as "net crude oil and natural gas sales," a non-GAAP measure. Average sales prices calculated using net crude oil and natural gas sales are referred to as "net sales prices," a non-GAAP measure, and are calculated by taking revenues less transportation expenses divided by sales volumes, whether for crude oil or natural gas, as applicable. Management believes presenting our revenues and sales prices net of transportation expenses is useful because it normalizes the presentation differences between operated and non-operated revenues and allows for a useful comparison of net realized prices to NYMEX benchmark prices on a Company-wide basis.
The following table presents a reconciliation of total Company crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the fourth quarter and full year periods of 2018.

Total Company	Fourth Quarter 2018			Year Ended December 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$900,872	$253,232	$1,154,104	$3,792,594	$886,128	$4,678,722
Less: Transportation expenses	(42,373)	(6,655)	(49,028)	(162,312)	(29,275)	(191,587)

Net crude oil and natural gas sales (non-GAAP for 2018)	$858,499	$246,577	$1,105,076	$3,630,282	$856,853	$4,487,135
Sales volumes (MBbl/MMcf/MBoe)	17,149	75,661	29,759	61,332	284,730	108,787
Net sales price (non-GAAP for 2018)	$50.06	$3.26	$37.13	$59.19	$3.01	$41.25

The following tables present reconciliations of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for North Dakota Bakken, SCOOP, and STACK for the year ended December 31, 2018 as presented in Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Production and Price History.

Year Ended December 31, 2018	North Dakota Bakken		
In thousands	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$2,797,771	$263,388	$3,061,159
Less: Transportation expenses	(128,287)	(2,291)	(130,578)
Net crude oil and natural gas sales (non-GAAP for 2018)	$2,669,484	$261,097	$2,930,581
Sales volumes (MBbl/MMcf/MBoe)	45,735	78,448	58,810
Net sales price (non-GAAP for 2018)	$58.37	$3.33	$49.83

Year Ended December 31, 2018	SCOOP		
In thousands	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$435,798	$351,021	$786,819
Less: Transportation expenses	(4,039)	(11,741)	(15,780)
Net crude oil and natural gas sales (non-GAAP for 2018)	$431,759	$339,280	$771,039
Sales volumes (MBbl/MMcf/MBoe)	6,882	99,397	23,447
Net sales price (non-GAAP for 2018)	$62.74	$3.41	$32.88

Year Ended December 31, 2018	STACK		
In thousands	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$227,615	$256,657	$484,272
Less: Transportation expenses	(4,574)	(15,184)	(19,758)
Net crude oil and natural gas sales (non-GAAP for 2018)	$223,041	$241,473	$464,514
Sales volumes (MBbl/MMcf/MBoe)	3,599	101,267	20,477
Net sales price (non-GAAP for 2018)	$61.97	$2.38	$22.68

PV-10

Our PV-10 value, a non-GAAP financial measure, is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2018, our PV-10 totaled approximately $18.7 billion. The standardized measure of our discounted future net cash flows was approximately $15.7 billion at December 31, 2018, representing a $3.0 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at Standardized Measure. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General. We are exposed to a variety of market risks including commodity price risk, credit risk, and interest rate risk. We seek to address these risks through a program of risk management which may include the use of derivative instruments.

Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the quarter ended December 31, 2018, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $682 million for each $10.00 per barrel change in crude oil prices and $300 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by market fluctuations in crude oil and natural gas prices, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds to be used for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. We have hedged the majority of our forecasted 2019 natural gas production. Our future crude oil production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

Changes in natural gas prices during the year ended December 31, 2018 had an overall unfavorable impact on the fair value of our derivative instruments. For the year ended December 31, 2018, we recognized cash losses on natural gas derivatives of $36.9 million which were partially offset by non-cash mark-to-market gains on natural gas derivatives of $13.0 million.

The fair value of our natural gas derivative instruments at December 31, 2018 was a net asset of $15.6 million. An assumed increase in the forward prices used in the year-end valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $84 million at December 31, 2018. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $116 million at December 31, 2018. Changes in the fair value of our natural gas derivatives from the above price sensitivities would produce a corresponding change in our total revenues.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($644 million in receivables at December 31, 2018); our joint interest and other receivables ($368 million at December 31, 2018); and counterparty credit risk associated with our derivative instrument receivables ($16 million at December 31, 2018).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty’s credit worthiness. We have not generally required our counterparties to provide collateral to secure crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $54 million at December 31, 2018, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on a co-owner's interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our revolving credit facility. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. We had no outstanding borrowings on our credit facility at January 31, 2019. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates.

We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2018:

In thousands	2019	2020	2021	2022	2023	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$—	$—	$—	$1,600,000	$1,500,000	$2,700,000	$5,800,000
Weighted-average interest rate	—	—	—	5.0 %	4.5 %	4.3 %	4.5 %
Note payable:							
Principal amount (1)	$2,360	$2,435	$2,515	$425	$—	$—	$7,735
Interest rate	3.1 %	3.1 %	3.1 %	3.1 %	—	—	3.1 %
Variable rate debt:							
Revolving credit facility:							
Principal amount	$—	$—	$—	$—	$—	$—	$—
Weighted-average interest rate	—	—	—	—	—	—	—

(1) Amounts represent scheduled maturities and do not reflect any discount or premium at which the notes were issued or any debt issuance costs.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the “Company”) as of December 31, 2018 and 2017, the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.
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, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated February 18, 2019 expressed an unqualified opinion.
Change in accounting principles
As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for revenue from contracts with customers due to the adoption of the new revenue standard. The Company adopted the new revenue standard using the modified retrospective approach. Our opinion is not modified with respect to this matter.
Basis for opinion
These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2004.

Oklahoma City, Oklahoma
February 18, 2019

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

In thousands, except par values and share data	December 31, 2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$282,749	$43,902
Receivables:		
Crude oil and natural gas sales	644,107	671,665
Affiliated parties	73	63
Joint interest and other, net	368,235	426,585
Derivative assets	15,612	2,603
Inventories	88,544	97,406
Prepaid expenses and other	13,041	9,501
Total current assets	1,412,361	1,251,725
Net property and equipment, based on successful efforts method of accounting	13,869,800	12,933,789
Other noncurrent assets	15,786	14,137
Total assets	$15,297,947	$14,199,651
Liabilities and equity		
Current liabilities:		
Accounts payable trade	$717,560	$692,908
Revenues and royalties payable	400,567	374,831
Payables to affiliated parties	203	143
Accrued liabilities and other	266,819	260,074
Current portion of long-term debt	2,360	2,286
Total current liabilities	1,387,509	1,330,242
Long-term debt, net of current portion	5,765,989	6,351,405
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,574,436	1,259,558
Asset retirement obligations, net of current portion	136,986	111,794
Other noncurrent liabilities	11,166	15,449
Total other noncurrent liabilities	1,722,588	1,386,801
Commitments and contingencies (Note 11)		
Equity:		
Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding	—	—
Common stock, $0.01 par value; 1,000,000,000 shares authorized; 376,021,575 shares issued and outstanding at December 31, 2018; 375,219,769 shares issued and outstanding at December 31, 2017	3,760	3,752
Additional paid-in capital	1,434,823	1,409,326
Accumulated other comprehensive income	415	307
Retained earnings	4,706,135	3,717,818
Total shareholders’ equity attributable to Continental Resources	6,145,133	5,131,203
Noncontrolling interests	276,728	—
Total equity	6,421,861	5,131,203
Total liabilities and equity	$15,297,947	$14,199,651

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)

	Year Ended December 31,		
In thousands, except per share data	2018	2017	2016
Revenues:			
Crude oil and natural gas sales	$4,678,722	$2,982,966	$2,026,958
Gain (loss) on crude oil and natural gas derivatives, net	(23,930)	91,647	(71,859)
Crude oil and natural gas service operations	54,794	46,215	25,174
Total revenues	4,709,586	3,120,828	1,980,273
Operating costs and expenses:			
Production expenses	390,423	324,214	289,289
Production taxes	353,140	208,278	142,388
Transportation expenses	191,587	—	—
Exploration expenses	7,642	12,393	16,972
Crude oil and natural gas service operations	21,639	16,880	11,386
Depreciation, depletion, amortization and accretion	1,859,327	1,674,901	1,708,744
Property impairments	125,210	237,370	237,292
General and administrative expenses	183,569	191,706	169,580
Litigation settlement	—	59,600	—
Net gain on sale of assets and other	(16,671)	(53,915)	(307,844)
Total operating costs and expenses	3,115,866	2,671,427	2,267,807
Income (loss) from operations	1,593,720	449,401	(287,534)
Other income (expense):			
Interest expense	(293,032)	(294,495)	(320,562)
Loss on extinguishment of debt	(7,133)	(554)	(26,055)
Other	3,247	1,715	1,697
	(296,918)	(293,334)	(344,920)
Income (loss) before income taxes	1,296,802	156,067	(632,454)
(Provision) benefit for income taxes	(307,102)	633,380	232,775
Net income (loss)	989,700	789,447	(399,679)
Net income attributable to noncontrolling interests	1,383	—	—
Net income (loss) attributable to Continental Resources	$988,317	$789,447	$(399,679)
Net income (loss) per share attributable to Continental Resources:			
Basic	$2.66	$2.13	$(1.08)
Diluted	$2.64	$2.11	$(1.08)
Comprehensive income (loss):			
Net income (loss)	$989,700	$789,447	$(399,679)
Other comprehensive income, net of tax:			
Foreign currency translation adjustments	108	567	3,094
Total other comprehensive income, net of tax	108	567	3,094
Comprehensive income (loss)	989,808	790,014	(396,585)
Comprehensive income (loss) attributable to noncontrolling interests	1,383	—	—
Comprehensive income (loss) attributable to Continental Resources	$988,425	$790,014	$(396,585)

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Equity

	Shareholders' equity attributable to Continental Resources							
In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income (loss)	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
Balance at December 31, 2015	372,959,080	$3,730	$1,345,624	$(3,354)	$3,322,900	$4,668,900	$—	$4,668,900
Net loss	—	—	—	—	(399,679)	(399,679)	—	(399,679)
Other comprehensive loss, net of tax	—	—	—	3,094	—	3,094	—	3,094
Stock-based compensation	—	—	48,084	—	—	48,084	—	48,084
Tax benefit from stock-based compensation	—	—	(9,828)	—	—	(9,828)	—	(9,828)
Restricted stock:								
Granted	2,064,508	20	—	—	—	20	—	20
Repurchased and canceled	(337,981)	(3)	(8,590)	—	—	(8,593)	—	(8,593)
Forfeited	(193,250)	(2)	—	—	—	(2)	—	(2)
Balance at December 31, 2016	374,492,357	$3,745	$1,375,290	$(260)	$2,923,221	$4,301,996	$—	$4,301,996
Cumulative effect adjustment from adoption of ASU 2016-09	—	—	—	—	5,150	5,150	—	5,150
Net income	—	—	—	—	789,447	789,447	—	789,447
Other comprehensive income, net of tax	—	—	—	567	—	567	—	567
Stock-based compensation	—	—	45,854	—	—	45,854	—	45,854
Restricted stock:								
Granted	1,585,870	16	—	—	—	16	—	16
Repurchased and canceled	(259,729)	(3)	(11,818)	—	—	(11,821)	—	(11,821)
Forfeited	(598,729)	(6)	—	—	—	(6)	—	(6)

Balance at December 31, 2017	375,219,769	$3,752	$1,409,326	$307	$3,717,818	$5,131,203	$—	$5,131,203
Net income	—	—	—	—	988,317	988,317	1,383	989,700
Other comprehensive income, net of tax	—	—	—	108	—	108	—	108
Equity transaction costs (see Note 15)	—	—	(4,838)	—	—	(4,838)	—	(4,838)
Stock-based compensation	—	—	47,223	—	—	47,223	—	47,223
Restricted stock:								
Granted	1,390,914	14	—	—	—	14	—	14
Repurchased and canceled	(310,822)	(3)	(16,888)	—	—	(16,891)	—	(16,891)
Forfeited	(278,286)	(3)	—	—	—	(3)	—	(3)
Contributions from noncontrolling interests	—	—	—	—	—	—	277,238	277,238
Distributions to noncontrolling interests	—	—	—	—	—	—	(1,893)	(1,893)
Balance at December 31, 2018	376,021,575	$3,760	$1,434,823	$415	$4,706,135	$6,145,133	$276,728	$6,421,861

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31,		
In thousands	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$989,700	$789,447	$(399,679)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	1,859,118	1,670,838	1,709,567
Property impairments	125,210	237,370	237,292
Non-cash (gain) loss on derivatives, net	(13,009)	(58,031)	156,621
Stock-based compensation	47,236	45,868	48,098
Tax benefit from US tax reform legislation	—	(713,655)	—
Provision (benefit) for deferred income taxes from operations	314,878	88,056	(209,836)
Tax deficiency from stock-based compensation	—	—	9,828
Dry hole costs	147	176	4,866
Litigation settlement	—	59,600	—
Gain on sale of assets, net	(16,671)	(55,124)	(304,489)
Loss on extinguishment of debt	7,133	554	26,055
Other, net	16,558	12,592	9,812
Changes in assets and liabilities:			
Accounts receivable	94,765	(329,811)	(158,383)
Inventories	7,735	14,517	(17,836)
Other current assets	(3,539)	1,038	968
Accounts payable trade	9,274	137,339	(14,404)
Revenues and royalties payable	24,010	158,982	30,455
Accrued liabilities and other	(4,162)	21,368	(883)
Other noncurrent assets and liabilities	(2,375)	(2,018)	(2,133)
Net cash provided by operating activities	3,456,008	2,079,106	1,125,919
Cash flows from investing activities:			
Exploration and development	(2,840,880)	(1,931,942)	(1,154,131)
Purchase of producing crude oil and natural gas properties	(31,579)	(8,446)	(5,008)
Purchase of other property and equipment	(42,171)	(12,810)	(5,375)
Proceeds from sale of assets	54,458	144,353	631,549
Net cash used in investing activities	(2,860,172)	(1,808,845)	(532,965)
Cash flows from financing activities:			
Credit facility borrowings	2,024,000	1,302,000	1,691,000
Repayment of credit facility	(2,212,000)	(2,019,000)	(1,639,000)
Proceeds from issuance of Senior Notes	—	990,000	—
Redemption of Senior Notes	(400,000)	—	(600,000)
Premium and costs on redemption of Senior Notes	(6,700)	—	(19,168)
Repayment of other debt	(2,286)	(502,214)	(2,144)
Debt issuance costs	(5,535)	(1,999)	(40)
Equity transaction costs	(4,838)	—	—
Contributions from noncontrolling interests	267,920	—	—
Distributions to noncontrolling interests	(604)	—	—
Repurchase of restricted stock for tax withholdings	(16,891)	(11,821)	(8,593)

Tax deficiency from stock-based compensation	—	—	(9,828)
Net cash used in financing activities	(356,934)	(243,034)	(587,773)
Effect of exchange rate changes on cash	(55)	32	(1)
Net change in cash and cash equivalents	238,847	27,259	5,180
Cash and cash equivalents at beginning of period	43,902	16,643	11,463
Cash and cash equivalents at end of period	$282,749	$43,902	$16,643

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

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Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
Note 1. Organization and Summary of Significant Accounting Policies
Description of the Company
Continental Resources, Inc. (the "Company") was originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company's principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. Additionally, the Company pursues the acquisition and management of perpetually owned minerals located in certain of its key operating areas. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.
Basis of presentation of consolidated financial statements
The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries, and entities in which the Company has a controlling financial interest. Intercompany accounts and transactions have been eliminated upon consolidation. Noncontrolling interests reflected herein represent third party ownership in the net assets of consolidated subsidiaries. The portions of consolidated net income and equity attributable to the noncontrolling interests are presented separately in the Company's financial statements.
Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates. The most significant estimates and assumptions impacting reported results are estimates of the Company's crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties.
Cash and cash equivalents
The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. As of December 31, 2018, the Company had cash deposits in excess of federally insured amounts of approximately $280.7 million. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk in this area.
Accounts receivable
Receivables arising from crude oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and are considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company's history of losses, and the customer or working interest owner's ability to pay. The Company writes off specific receivables when they become noncollectable and any payments subsequently received on those receivables are credited to the allowance for doubtful accounts. Write-offs of noncollectable receivables have historically not been material. The Company's allowance for doubtful accounts totaled $2.4 million and $2.2 million as of December 31, 2018 and 2017, respectively, which is included in "Receivables—Joint interest and other, net" on the consolidated balance sheets.
Concentration of credit risk
The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with significant purchasers. For the year ended December 31, 2018, sales to the Company's largest purchaser accounted for approximately 12% of the Company's total crude oil and natural gas sales. No other purchaser accounted for more than 10% of the Company's total crude oil and natural gas sales for 2018. The Company generally does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude

oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

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Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines, pipeline imbalances, and tubular goods and equipment to be used in the Company’s exploration and development activities. Crude oil inventories are valued at the lower of cost or net realizable value primarily using the first-in, first-out inventory method. Tubular goods and equipment are valued primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of December 31, 2018 and 2017 consisted of the following:

	December 31,	
In thousands	2018	2017
Tubular goods and equipment	$14,623	$14,946
Crude oil	73,921	82,460
Total	$88,544	$97,406

Crude oil and natural gas properties

The Company uses the successful efforts method of accounting for crude oil and natural gas properties whereby costs incurred to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells, and expenditures for enhanced recovery operations are capitalized. Geological and geophysical costs, seismic costs incurred for exploratory projects, lease rentals and costs associated with unsuccessful exploratory wells or projects are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. To the extent a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between capitalized development costs and exploration expense. Maintenance, repairs, and costs of injection are expensed as incurred.

Under the successful efforts method of accounting, the Company capitalizes exploratory drilling costs on the balance sheet pending determination of whether the well has found proved reserves in economically producible quantities. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, the associated capitalized costs become part of well equipment and facilities. However, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value.

Production expenses are those costs incurred by the Company to operate and maintain its crude oil and natural gas properties and associated equipment and facilities. Production expenses include but are not limited to labor costs to operate the Company’s properties, repairs and maintenance, certain waste water disposal costs, utility costs, certain workover-related costs, and materials and supplies utilized in the Company’s operations.

Service property and equipment

Service property and equipment consist primarily of automobiles and aircraft; machinery and equipment; gathering and recycling systems; storage tanks; office and computer equipment, software, furniture and fixtures; and buildings and improvements. Major renewals and replacements are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

Depreciation and amortization of service property and equipment are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. The estimated useful lives of service property and equipment are as follows:

Service property and equipment	Useful Lives In Years
Automobiles and aircraft	5-10
Machinery and equipment	6-10
Gathering and recycling systems	15-30
Storage tanks	10-30
Office and computer equipment, software, furniture and fixtures	3-25

Buildings and improvements	4-40

Depreciation, depletion and amortization

Depreciation, depletion and amortization of capitalized drilling and development costs of producing crude oil and natural gas properties, including related support equipment and facilities, are computed using the unit-of-production method on a field basis based on total estimated proved developed reserves. Amortization of producing leaseholds is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable crude oil and natural gas reserves are established based on estimates made by the Company's internal geologists and engineers and external independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least in conjunction with semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Asset retirement obligations

The Company accounts for its asset retirement obligations by recording the fair value of a liability for an asset retirement obligation in the period in which a legal obligation is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the capitalized asset retirement costs are charged to expense through the depreciation, depletion and amortization of crude oil and natural gas properties and the liability is accreted to the expected future abandonment cost ratably over the related asset's life.

The Company's primary asset retirement obligations relate to future plugging and abandonment costs and related disposal of facilities on its crude oil and natural gas properties. The following table summarizes the changes in the Company's future abandonment liabilities from January 1, 2016 through December 31, 2018:

In thousands	2018	2017	2016
Asset retirement obligations at January 1	$114,406	$96,178	$102,909
Accretion expense	6,985	5,886	6,086
Revisions (1)	13,075	7,801	(12,755)
Plus: Additions for new assets	9,070	6,884	2,692
Less: Plugging costs and sold assets	(2,176)	(2,343)	(2,754)
Total asset retirement obligations at December 31	$141,360	$114,406	$96,178
Less: Current portion of asset retirement obligations at December 31 (2)	4,374	2,612	1,742
Non-current portion of asset retirement obligations at December 31	$136,986	$111,794	$94,436

(1) Revisions primarily represent changes in the present value of liabilities resulting from changes in estimated costs and economic lives of producing properties.

(2) Balance is included in the caption "Accrued liabilities and other" in the consolidated balance sheets.

As of December 31, 2018 and 2017, net property and equipment on the consolidated balance sheets included $57.7 million and $40.0 million, respectively, of net asset retirement costs.

Asset impairment

Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value.

Impairment losses for unproved properties are generally recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The Company's impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management.

Debt issuance costs

Costs incurred in connection with the execution of the Company's note payable and revolving credit facility and any amendments thereto are capitalized and amortized over the terms of the arrangements on a straight-line basis, the use of which approximates the effective interest method. Costs incurred upon the issuances of the Company's various senior notes (collectively, the “Notes”) were capitalized and are being amortized over the terms of the Notes using the effective interest method.

The Company had aggregate capitalized costs of $51.2 million and $58.2 million (net of accumulated amortization of $62.5 million and $51.8 million) relating to its long-term debt at December 31, 2018 and 2017, respectively. Unamortized capitalized costs associated with the Company’s Notes and note payable totaled $45.1 million and $55.0 million at December 31, 2018 and 2017, respectively, and are reflected as a reduction of “Long-term debt, net of current portion” on the consolidated balance sheets. Unamortized capitalized costs associated with the Company’s revolving credit facility totaled $6.1 million and $3.2 million at December 31, 2018 and 2017, respectively, and are reflected in “Other noncurrent assets” on the consolidated balance sheets.

For the years ended December 31, 2018, 2017 and 2016, the Company recognized amortization expense associated with capitalized debt issuance costs of $9.3 million, $9.1 million and $9.8 million, respectively, which are reflected in “Interest expense” on the consolidated statements of comprehensive income (loss).

Derivative instruments

The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value with such amounts classified as current or long-term based on contractual settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the changes in fair value in the consolidated statements of comprehensive income (loss). Gains and losses on crude oil and natural gas derivatives are reflected in the caption “Gain (loss) on crude oil and natural gas derivatives, net.” Gains and losses on diesel fuel derivatives are reflected in the caption “Operating costs and expenses—Net gain on sale of assets and other.”

Fair value of financial instruments

The Company’s financial instruments consist primarily of cash, trade receivables, trade payables, derivative instruments and long-term debt. See Note 6. Fair Value Measurements for a discussion of the methods used to determine fair value for the Company’s financial instruments and the quantification of fair value for its derivatives and long-term debt obligations at December 31, 2018 and 2017.

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. The Company’s policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. The Company recorded valuation allowances of $0.3 million, $0.4 million, and $1.0 million for the years ended December 31, 2018, 2017, and 2016, respectively, against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary for which the Company does not expect to realize a benefit.

Earnings per share attributable to Continental Resources

Basic net income (loss) per share is computed by dividing net income (loss) attributable to the Company by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects the potential dilution of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share attributable to the Company for the years ended December 31, 2018, 2017 and 2016.

	Year ended December 31,		
In thousands, except per share data	2018	2017	2016
Net income (loss) attributable to Continental Resources (numerator) (1)	$988,317	$789,447	$(399,679)
Weighted average shares (denominator):			
Weighted average shares - basic	371,854	371,066	370,380
Non-vested restricted stock (2)	2,984	2,702	—
Weighted average shares - diluted	374,838	373,768	370,380
Net income (loss) per share attributable to Continental Resources: (1)			
Basic	$2.66	$2.13	$(1.08)
Diluted	$2.64	$2.11	$(1.08)

(1) The Company remeasured its deferred income tax assets and liabilities at year-end 2017 in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time decrease in income tax expense and corresponding increase in net income of $713.7 million ($1.92 per basic share and $1.91 per diluted share) for 2017. See Note 9. Income Taxes for further discussion. Additionally, 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Note 11. Commitments and Contingencies—Litigation, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

(2) For the year ended December 31, 2016, the Company had a net loss and therefore the potential dilutive effect of approximately 2,303,000 weighted average non-vested restricted shares were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computation.

Foreign currency translation

In 2014, the Company initiated exploratory drilling activities in Canada through a wholly-owned Canadian subsidiary. The Company’s operations in Canada are immaterial. The Company has designated the Canadian dollar as the functional currency for its Canadian operations. Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in “Accumulated other comprehensive income” within equity on the consolidated balance sheets and “Other comprehensive income, net of tax” in the consolidated statements of comprehensive income (loss).

Adoption of new accounting pronouncements in 2018

Revenue recognition and presentation – In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606), which superseded nearly all previously existing revenue recognition guidance under U.S. GAAP. Subsequently, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This new guidance became effective for reporting periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on January 1, 2018 as required. See Note 8. Revenues for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New accounting pronouncements not yet adopted at December 31, 2018

Leases – In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard became effective for interim and annual reporting periods beginning after December 15, 2018. The Company adopted the new standard on January 1, 2019 on a prospective basis using the simplified transition method prescribed by ASU 2018-11, Leases (Topic 842): Targeted Improvements. Offsetting lease assets and lease liabilities recognized by the Company on the adoption date totaled approximately $19 million, representing minimum payment obligations associated with drilling rig commitments, surface use agreements, equipment, and other leases with contractual durations in excess of one year. Such leases, all of which are operating leases, had a weighted average remaining life and discount rate of 5.4 years and 4.5%, respectively, as of January 1, 2019. The Company has elected to account for lease and non-lease components in its contracts as a single lease component for all asset classes. Additionally, the Company has elected not to apply the recognition requirements of ASU 2016-02 to leases with durations of twelve months or less. No cumulative-effect adjustment to retained earnings was recognized upon adoption of the new lease standard.

The value of lease assets and lease liabilities recognized under ASU 2016-02 will change with the passage of time and from changes in the nature, timing, and extent of the Company's contractual lease arrangements in effect from period to period. As a result, the lease assets and liabilities recognized by the Company as of January 1, 2019 may not be indicative of amounts to be recognized in future periods. The Company continues to work on finalizing its implementation of procedures to comply with the new disclosure requirements prescribed by ASU 2016-02.

Credit losses – In June 2016, the FASB issued ASU 2016-13, Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost. The standard is effective for interim and annual periods beginning after December 15, 2019 and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. The Company continues to evaluate the new standard and is unable to estimate its financial statement impact at this time; however, the impact is not expected to be material. Historically, the Company's credit losses on crude oil and natural gas sales receivables and joint interest receivables have been immaterial.

Note 2. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income tax payments and refunds. Also disclosed is information about investing activities that affects recognized assets and liabilities but does not result in cash receipts or payments.

	Year ended December 31,		
In thousands	2018	2017	2016
Supplemental cash flow information:			
Cash paid for interest	$270,927	$281,058	$316,116
Cash paid for income taxes	—	2	2
Cash received for income tax refunds	7,893	257	174
Non-cash investing activities:			
Asset retirement obligation additions and revisions, net	22,145	14,685	(10,063)

As of December 31, 2018 and 2017, the Company had $317.5 million and $302.8 million, respectively, of accrued capital expenditures included in “Net property and equipment” and “Accounts payable trade” in the consolidated balance sheets.

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2018 and 2017.

	December 31,	
In thousands	2018	2017
Proved crude oil and natural gas properties	$24,060,625	$21,362,199
Unproved crude oil and natural gas properties	291,564	365,413
Service properties, equipment and other	324,758	290,111
Total property and equipment	24,676,947	22,017,723

Accumulated depreciation, depletion and amortization	(10,807,147)	(9,083,934)
Net property and equipment	$13,869,800	$12,933,789

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Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Note 4. Accrued Liabilities and Other
Accrued liabilities and other includes the following at December 31, 2018 and 2017:

	December 31,	
In thousands	2018	2017
Prepaid advances from joint interest owners	$53,674	$34,511
Accrued compensation	69,338	65,308
Accrued production taxes, ad valorem taxes and other non-income taxes	52,105	40,611
Accrued interest	64,483	55,282
Accrued litigation settlement (see Note 11)	19,753	59,600
Current portion of asset retirement obligations	4,374	2,612
Other	3,092	2,150
Accrued liabilities and other	$266,819	$260,074

Note 5. Derivative Instruments
Crude oil and natural gas derivatives
From time to time the Company has entered into crude oil and natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of crude oil and natural gas production. The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its crude oil and natural gas derivative instruments as hedges for accounting purposes and, as a result, marks such derivative instruments to fair value and recognizes the changes in fair value in the consolidated statements of comprehensive income (loss) under the caption “Gain (loss) on crude oil and natural gas derivatives, net.”
The Company's natural gas derivative contracts are settled based upon reported NYMEX Henry Hub settlement prices. The estimated fair value of derivatives is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars and written call options, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars and written call options requires the use of an option-pricing model. See Note 6. Fair Value Measurements.
With respect to a natural gas fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a natural gas collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.
At December 31, 2018, the Company had outstanding natural gas derivative contracts as set forth in the table below. The volumes reflected below represent an aggregation of multiple derivative contracts having similar remaining durations expected to be realized ratably over the reflected periods. At December 31, 2018 the Company had no outstanding crude oil derivative contracts.

			Floors		Ceilings	
Period and Type of Contract	MMBtus	Swaps Weighted Average Price	Range	Weighted average price	Range	Weighted average price
January 2019 - March 2019						
Swaps - Henry Hub	4,950,000	$ 4.70				
April 2019 - December 2019						
Swaps - Henry Hub	95,425,000	$ 2.78				

January 2019 - March 2019					
Collars - Henry Hub	4,950,000	$4.25	$ 4.25	$5.50 - $5.58	$ 5.52

Crude oil and natural gas derivative gains and losses

Cash receipts and payments in the following table reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

	Year ended December 31,		
In thousands	2018	2017	2016
Cash received (paid) on derivatives:			
Natural gas fixed price swaps	$(36,939)	$40,095	$88,823
Natural gas collars	—	(10,539)	—
Cash received (paid) on derivatives, net	(36,939)	29,556	88,823
Non-cash gain (loss) on derivatives:			
Crude oil written call options	—	—	38
Natural gas fixed price swaps	7,527	18,960	(120,784)
Natural gas collars	5,482	43,131	(39,936)
Non-cash gain (loss) on derivatives, net	13,009	62,091	(160,682)
Gain (loss) on crude oil and natural gas derivatives, net	$(23,930)	$91,647	$(71,859)

Diesel fuel derivatives

The Company previously entered into diesel fuel swap derivative contracts, all of which matured on or before December 31, 2017, to economically hedge against the variability in cash flows associated with purchases of diesel fuel for use in drilling activities. The Company did not designate its diesel fuel derivatives as hedges for accounting purposes and, as a result, marked the derivative instruments to fair value and recognized the changes in fair value in the consolidated statements of comprehensive income (loss) under the caption “Operating costs and expenses—Net gain on sale of assets and other.”

Cash receipts in the following table reflect gains on diesel fuel derivatives which matured during the respective period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of diesel fuel derivatives held at period end, if any, and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the respective period.

	Year ended December 31,	
In thousands	2017	2016
Cash received on diesel fuel derivatives	$2,845	$699
Non-cash gain (loss) on diesel fuel derivatives	(4,060)	4,060
Gain (loss) on diesel fuel derivatives, net	$(1,215)	$4,759

Balance sheet offsetting of derivative assets and liabilities

The Company’s derivative contracts are recorded at fair value in the consolidated balance sheets under the captions “Derivative assets”, “Noncurrent derivative assets”, “Derivative liabilities”, and “Noncurrent derivative liabilities”, as applicable. Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the consolidated balance sheets.

The following table presents the gross amounts of recognized natural gas derivative assets and liabilities, as applicable, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value.

	December 31,	
In thousands	2018	2017
Commodity derivative assets:		
Gross amounts of recognized assets	$16,789	$2,603
Gross amounts offset on balance sheet	(1,177)	—
Net amounts of assets on balance sheet	15,612	2,603
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(1,177)	—
Gross amounts offset on balance sheet	1,177	—
Net amounts of liabilities on balance sheet	$—	$—

The following table reconciles the net amounts disclosed above to the individual financial statement line items in the consolidated balance sheets.

	December 31,	
In thousands	2018	2017
Derivative assets	$15,612	$2,603
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	15,612	2,603
Derivative liabilities	—	—
Noncurrent derivative liabilities	—	—
Net amounts of liabilities on balance sheet	—	—
Total derivative assets, net	$15,612	$2,603

Note 6. Fair Value Measurements

The Company follows 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: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3: Unobservable inputs not corroborated by market data and may be used with internally developed methodologies that result in management’s best estimate of fair value.

A financial instrument’s categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available. The Company’s policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Assets and liabilities measured at fair value on a recurring basis

The Company's derivative instruments are reported at fair value on a recurring basis. In determining the fair values of swap contracts, a discounted cash flow method is used due to the unavailability of relevant comparable market data for the Company's exact contracts. The discounted cash flow method estimates future cash flows based on quoted market prices for forward commodity prices and a risk-adjusted discount rate. The fair values of swap contracts are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collars requires the use of an industry-standard option pricing model that considers various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. These assumptions are observable in the marketplace or can be corroborated by active markets or broker quotes and are therefore designated as Level 2 within the valuation hierarchy. The Company's calculation of fair value for each of its derivative positions is compared to the counterparty valuation for reasonableness.

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2018 and 2017.

	Fair value measurements at December 31, 2018 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$ 10,130	$ —	$ 10,130
Collars	—	5,482	—	5,482
Total	$ —	$ 15,612	$ —	$ 15,612

	Fair value measurements at December 31, 2017 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$ 2,603	$ —	$ 2,603
Total	$ —	$ 2,603	$ —	$ 2,603

Assets measured at fair value on a nonrecurring basis

Certain assets are reported at fair value on a nonrecurring basis in the consolidated financial statements. The following methods and assumptions were used to estimate the fair values for those assets.

Asset impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips adjusted for differentials, operating costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company at December 31, 2018 to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

Unobservable Input	Assumption
Future production	Future production estimates for each property

Forward commodity prices	Forward NYMEX strip prices through 2023 (adjusted for differentials), escalating 3% per year thereafter
Operating costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of properties	Up to 50 years
Discount rate	10%

Unobservable inputs to the fair value assessment are reviewed quarterly and are revised as warranted based on a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Fair value measurements of proved properties are reviewed and approved by certain members of the Company's management.

For the years ended December 31, 2018, 2017, and 2016, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Such impairments totaled $18.0 million for 2018, which reflect write-offs of various non-core properties in the North and South regions. Impairments of proved properties totaled $82.3 million for 2017, which reflect fair value adjustments in the Arkoma Woodford field ($81.2 million) and various non-core properties in the North and South regions ($1.1 million). The impaired properties in 2017 were written down to their estimated fair value at the time of impairment of $72 million. Impairments of proved properties totaled $2.9 million for 2016 primarily related to non-core properties in the North region that were written down to their estimated fair value at the time of impairment of $0.7 million.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2018, 2017, and 2016, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

The following table sets forth the non-cash impairments of both proved and unproved properties for the indicated periods. Proved and unproved property impairments are recorded under the caption "Property impairments" in the consolidated statements of comprehensive income (loss).

	Year ended December 31,		
In thousands	2018	2017	2016
Proved property impairments	$18,037	$82,340	$2,895
Unproved property impairments	107,173	155,030	234,397
Total	$125,210	$237,370	$237,292

Financial instruments not recorded at fair value

The following table sets forth the estimated fair values of financial instruments that are not recorded at fair value in the consolidated financial statements.

	December 31, 2018		December 31, 2017	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Revolving credit facility	$—	$—	$188,000	$188,000
Note payable	7,700	7,700	9,974	9,900
5% Senior Notes due 2022	1,598,404	1,590,900	1,997,576	2,040,000
4.5% Senior Notes due 2023	1,488,960	1,476,300	1,486,690	1,526,800
3.8% Senior Notes due 2024	993,151	947,200	992,036	988,800
4.375% Senior Notes due 2028	988,617	942,800	988,061	987,200
4.9% Senior Notes due 2044	691,517	618,800	691,354	679,900
Total debt	$5,768,349	$5,583,700	$6,353,691	$6,420,600

The fair value of revolving credit facility borrowings approximate carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and are classified as Level 2 in the fair value hierarchy.

The fair value of the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of the note payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of the note payable is classified as Level 3 in the fair value hierarchy.

The fair values of the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 (“2023 Notes”), the 3.8% Senior Notes due 2024 (“2024 Notes”), the 4.375% Senior Notes due 2028 (“2028 Notes”), and the 4.9% Senior Notes due 2044 (“2044 Notes”) are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

Note 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $39.4 million and $44.3 million at December 31, 2018 and 2017, respectively, consists of the following.

	December 31,	
In thousands	2018	2017
Revolving credit facility	$—	$188,000
Note payable	7,700	9,974
5% Senior Notes due 2022	1,598,404	1,997,576
4.5% Senior Notes due 2023	1,488,960	1,486,690
3.8% Senior Notes due 2024	993,151	992,036
4.375% Senior Notes due 2028	988,617	988,061
4.9% Senior Notes due 2044	691,517	691,354
Total debt	5,768,349	6,353,691
Less: Current portion of long-term debt	2,360	2,286
Long-term debt, net of current portion	$5,765,989	$6,351,405

Revolving credit facility

In April 2018, the Company entered into a new unsecured revolving credit facility, maturing in April 2023, with aggregate commitments totaling $1.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. In connection with the execution of the new credit facility, the Company terminated its then-existing $2.75 billion credit facility that was due to mature in May 2019. The Company had no outstanding borrowings on its credit facility at December 31, 2018.

Borrowings under the credit facility, if any, bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company’s senior, unsecured, long-term indebtedness. The Company incurs commitment fees based on currently assigned credit ratings of 0.20% per annum on the daily average amount of unused borrowing availability under its credit facility.

The credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders’ equity plus, to the extent resulting in a reduction of total shareholders’ equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the credit facility covenants at December 31, 2018.

Senior notes

The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company’s outstanding senior note obligations at December 31, 2018.

	2022 Notes (1)	2023 Notes	2024 Notes	2028 Notes	2044 Notes
Face value (in thousands)	$1,600,000	$1,500,000	$1,000,000	$1,000,000	$700,000
Maturity date	Sep 15, 2022	April 15, 2023	June 1, 2024	January 15, 2028	June 1, 2044
Interest payment dates	March 15, Sep 15	April 15, Oct 15	June 1, Dec 1	Jan 15, July 15	June 1, Dec 1
Make-whole redemption period (2)	—	Jan 15, 2023	Mar 1, 2024	Oct 15, 2027	Dec 1, 2043

(1) The Company has the option to redeem all or a portion of its remaining 2022 Notes at the decreasing redemption prices specified in the indenture related to the 2022 Notes plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to the indicated dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the "make-whole" redemption amounts specified in the respective senior note indentures plus any accrued and unpaid interest to the date of redemption. On or after the indicated dates, the Company may redeem all or a portion of its senior notes at a redemption amount equal to 100% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption.

The Company's senior notes are not subject to any mandatory redemption or sinking fund requirements.

The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, or consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at December 31, 2018.

Three of the Company's wholly-owned subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, the value of whose assets, equity, and results of operations are minor, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company's other subsidiaries, the value of whose assets, equity, and results of operations attributable to the Company are minor, do not guarantee the senior notes.

2018 partial redemption of senior notes

In August 2018, the Company redeemed $400 million, or 20%, of its previously outstanding $2.0 billion of 5% Senior Notes due 2022. The redemption price was equal to 101.667% of the principal amount called for redemption plus accrued and unpaid interest to the redemption date in accordance with the terms of the 2022 Notes and the related indenture under which the 2022 Notes were issued.

The aggregate of the principal amount, redemption premium, and accrued interest paid upon redemption of the 2022 Notes was $415.1 million. The Company recorded a pre-tax loss on extinguishment of debt related to the redemption of $7.1 million, which included the redemption premium and pro-rata write-off of deferred financing costs and unamortized debt premium associated with the notes. The loss is reflected under the caption "Loss on extinguishment of debt" in the consolidated statements of comprehensive income (loss).

Note payable

In February 2012, 20 Broadway Associates LLC, a wholly-owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.4 million is reflected as a current liability under the caption "Current portion of long-term debt" in the consolidated balance sheets as of December 31, 2018.

Note 8. Revenues

Adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received, allocate the consideration to each separate performance obligation, and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition.

Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity records revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Applying the guidance in ASU 2016-08 requires significant judgment in determining the point in time when control of products transfers to customers.

The Company adopted the new revenue recognition and presentation guidance on January 1, 2018 using a modified retrospective transition approach to all applicable contracts at the date of initial application, whereby the standard has been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation. Adoption of the new guidance had no cumulative effect impact on the Company's retained earnings at January 1, 2018.

The new guidance does not have a material impact on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows, but does impact the Company's presentation of revenues and expenses under the gross-versus-net presentation guidance in ASU 2016-08. In years prior to 2018, the Company generally presented its revenues net of costs incurred to transport its production to market. Under the new guidance, revenues and transportation expenses associated with production originating from the Company's operated properties are now reported on a gross basis as further discussed below. The changes from net to gross presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company's results of operations, net income, or cash flows for the year ended December 31, 2018.

The following table reflects the change in presentation of revenues and applicable expenses on the Company's 2018 results under the new and previous guidance.

	Year ended December 31, 2018		
In thousands	New Standard	Prior Presentation	Change
Revenues:			
Crude oil and natural gas sales	$4,678,722	$4,487,135	$191,587
Loss on natural gas derivatives, net	(23,930)	(23,930)	—
Crude oil and natural gas service operations	54,794	54,794	—
Total revenues	$4,709,586	$4,517,999	$191,587
Operating costs and expenses:			
Transportation expenses	$191,587	$—	$191,587
Net income	$989,700	$989,700	$—

Revenue from contracts with customers

Below is a discussion of the nature, timing, and presentation of revenues arising from the Company's major revenue-generating arrangements.

Operated crude oil revenues – The Company pays third parties to transport the majority of its operated crude oil production from lease locations to downstream market centers, at which time the Company's customers take title and custody of the product in exchange for prices based on the particular market where the product was delivered. Operated crude oil revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. Crude oil sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred. Operated crude oil revenues and transportation expenses are reported on a gross basis, as the Company controls the operated production prior to its transfer to customers. Transportation expenses associated with the Company's operated crude oil production totaled $162.3 million for the year ended December 31, 2018.

Operated natural gas revenues – The Company sells the majority of its operated natural gas production to midstream customers at its lease locations based on market prices in the field where the sales occur. Under these arrangements, the midstream customers obtain control of the unprocessed gas stream at the lease location and the Company's revenues from each sale are determined using contractually agreed pricing formulas which contain multiple components, including the volume and Btu content of the natural gas sold, the midstream customer's proceeds from the sale of residue gas and natural gas liquids ("NGLs") at secondary downstream markets, and contractual pricing adjustments reflecting the midstream customer's estimated recoupment of its investment over time. Such revenues are recognized net of pricing adjustments applied by the midstream customer during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Natural gas sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred.

Under certain arrangements, the Company has the right to take a volume of processed residue gas and/or NGLs in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement for the sale of the Company's operated natural gas production. When the Company elects to take volumes in kind, it pays third parties to transport the processed products it took in-kind to downstream delivery points, where it then sells to customers at prices applicable to those downstream markets. In such situations, operated revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Operated sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, the Company's revenues include the pricing adjustments applied by the midstream processing entity according to the applicable contractual pricing formula, but exclude the transportation expenses the Company incurs to transport the processed products to downstream customers. Transportation expenses associated with these arrangements totaled $29.3 million for the year ended December 31, 2018, comprised entirely of costs to transport processed residue gas.

Non-operated crude oil and natural gas revenues – The Company's proportionate share of production from non-operated properties is generally marketed at the discretion of the operators. For non-operated properties, the Company receives a net payment from the operator representing its proportionate share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds to be received by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive. Proceeds are generally received by the Company within two to three months after the month in which production occurs.

Revenues from derivative instruments – See Note 5. Derivative Instruments for discussion of the Company's accounting for its derivative instruments.

Revenues from service operations – Revenues from the Company's crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of crude oil reclaimed from waste products. Revenues associated with such activities, which are derived using market-based rates or rates commensurate with industry guidelines, are recognized during the month in which services are performed, the Company has an unconditional right to receive payment, and collectability is probable. Payment is generally received by the Company within one month after the month in which services are provided.

Disaggregation of crude oil and natural gas revenues

The following table presents the disaggregation of the Company's crude oil and natural gas revenues for the year ended December 31, 2018.

	Year ended December 31, 2018		
In thousands	North Region	South Region	Total
Crude oil revenues:			
Operated properties	$2,330,711	$603,070	$2,933,781
Non-operated properties	790,435	68,378	858,813
Total crude oil revenues	3,121,146	671,448	3,792,594
Natural gas revenues:			
Operated properties	214,741	547,247	761,988
Non-operated properties	60,738	63,402	124,140
Total natural gas revenues	275,479	610,649	886,128
Crude oil and natural gas sales	$3,396,625	$1,282,097	$4,678,722
Timing of revenue recognition			
Goods transferred at a point in time	$3,396,625	$1,282,097	$4,678,722
Goods transferred over time	—	—	—

$3,396,625	$1,282,097	$4,678,722

Performance obligations

The Company satisfies the performance obligations under its crude oil and natural gas sales contracts upon delivery of its production and related transfer of control to customers. Upon delivery of production, the Company has a right to receive consideration from its customers in amounts determined by the sales contracts.

All of the Company's outstanding crude oil sales contracts at December 31, 2018 are short-term in nature with contract terms of less than one year. For such contracts, the Company has utilized the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

The majority of the Company's operated natural gas production is sold at lease locations to midstream customers under multi-year term contracts. For such contracts having a term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14A which indicates an entity is not required to disclose the transaction price allocated to remaining performance obligations, if any, if variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our sales contracts, whether for crude oil or natural gas, each unit of production delivered to a customer represents a separate performance obligation; therefore, future volumes to be delivered are wholly unsatisfied at period-end and disclosure of the transaction price allocated to remaining performance obligations is not applicable.

Contract balances

Under the Company’s crude oil and natural gas sales contracts or activities that give rise to service revenues, the Company recognizes revenue after its performance obligations have been satisfied, at which point the Company has an unconditional right to receive payment. Accordingly, the Company’s commodity sales contracts and service activities generally do not give rise to contract assets or contract liabilities under ASC Topic 606. Instead, the Company's unconditional rights to receive consideration are presented as a receivable within "Receivables–Crude oil and natural gas sales" or "Receivables–Joint interest and other, net", as applicable, in its consolidated balance sheets.

Revenues from previously satisfied performance obligations

To record revenues for commodity sales, at the end of each month the Company estimates the amount of production delivered and sold to customers and the prices to be received for such sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer and are reflected in the financial statements within the caption "Crude oil and natural gas sales". Revenues recognized during the year ended December 31, 2018 related to performance obligations satisfied in prior reporting periods were not material.

Note 9. Income Taxes

In December 2017, the Tax Cuts and Jobs Act was signed into law. The legislation contained several key changes to U.S. corporate tax laws, including a reduction of the corporate income tax rate from 35% to 21%, effective January 1, 2018. The legislation also included a variety of other changes such as the repeal of the alternative minimum tax; the introduction of new limitations on the tax deductibility of net operating losses, interest expenses, and executive compensation expenses; the acceleration of expensing of certain qualified property; and the introduction of new laws governing taxation of foreign earnings of U.S. entities, among others.

The Company recognizes the effect of tax law changes in the reporting period that includes the enactment date in accordance with U.S. GAAP. As a result, the Company remeasured its deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the corporate tax rate from 35% to 21% enacted into law in December 2017. This remeasurement resulted in a $713.7 million decrease in net deferred income tax liabilities and corresponding decrease in income tax expense as of and for the year ended December 31, 2017, which is reflected in the tables below. The Company's accounting for the effects of the tax rate change on its deferred tax balances as well as other relevant aspects of the Tax Cuts and Jobs Act was completed as of December 31, 2017 and no provisional amounts were recorded at that date that were later adjusted in 2018.

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The items comprising the Company's (provision) benefit for income taxes are as follows for the periods presented:

	Year ended December 31,		
In thousands	2018	2017	2016
Current income tax (provision) benefit:			
United States federal (1)	$7,781	$7,781	$22,941
Various states	(5)	—	(2)
Total current income tax benefit	7,776	7,781	22,939
Deferred income tax (provision) benefit:			
United States federal - taxation on operations	(282,947)	(81,054)	182,422
United States federal - effect of US tax reform	—	713,655	—
Various states	(31,931)	(7,002)	27,414
Total deferred income tax (provision) benefit	(314,878)	625,599	209,836
(Provision) benefit for income taxes	$(307,102)	$633,380	$232,775

(1) The current federal income tax benefits represent alternative minimum tax refunds.

The (provision) benefit for income taxes differs from the amount computed by applying the United States statutory federal income tax rate to income (loss) before income taxes. The sources and tax effects of the difference are as follows:

	Year ended December 31,					
	2018		2017		2016	
In thousands, except rates	Amount	Rate	Amount	Rate	Amount	Rate
Expected income tax (provision) benefit based on US statutory tax rate	$(272,328)	21.0%	$(54,623)	35.0 %	$221,359	35.0%
State income taxes, net of federal benefit	(45,920)	3.6 %	(4,682)	3.0 %	18,829	3.0 %
Effect of US tax reform legislation	—	— %	713,655	(457.3%)	—	— %
Tax (benefit) deficiency from stock-based compensation	259	— %	(3,932)	2.5 %	—	— %
Non-deductible compensation	(2,932)	0.2 %	(13,813)	8.9 %	(3,471)	(0.5 %)
Other, net	13,819	(1.1 %)	(3,225)	2.1 %	(3,942)	(0.7 %)
(Provision) benefit for income taxes	$(307,102)	23.7%	$633,380	(405.8%)	$232,775	36.8%

The components of the Company’s deferred tax assets and deferred tax liabilities as of December 31, 2018 and 2017 are reflected in the table below.

	December 31,	
In thousands	2018	2017
Deferred tax assets		
United States net operating loss carryforwards	$549,166	$604,423
Canadian net operating loss carryforwards	19,633	19,341
Alternative minimum tax carryforwards	—	7,781
Equity compensation	13,122	12,962
Other	13,622	21,885
Total deferred tax assets	595,543	666,392
Canadian valuation allowance	(19,633)	(19,341)
Total deferred tax assets, net of valuation allowance	575,910	647,051
Deferred tax liabilities		
Property and equipment	(2,144,767)	(1,903,451)
Other	(5,579)	(3,158)
Total deferred tax liabilities	(2,150,346)	(1,906,609)
Deferred income tax liabilities, net	$(1,574,436)	$(1,259,558)

As of December 31, 2018, the Company had federal and state net operating loss carryforwards of $1.95 billion and $3.17 billion, respectively. The federal net operating loss carryforward will begin expiring in 2035. The Company’s net operating loss carryforward in Oklahoma totaled $2.14 billion at December 31, 2018, which will begin to expire in 2028. The Company’s net operating loss carryforward in North Dakota totaled $898 million at December 31, 2018, which will begin to expire in 2035. Any available statutory depletion carryforwards will be recognized when realized.

The Company files income tax returns in the U.S. federal, U.S. state and Canadian jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years prior to 2015.

The Company recorded valuation allowances of $0.3 million, $0.4 million, and $1.0 million against Canadian deferred tax assets for the years ended December 31, 2018, 2017, and 2016, respectively. The Company's cumulative valuation allowance was $19.6 million as of December 31, 2018. Our Canadian subsidiary has generated operating loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable could change if our subsidiary generates taxable income.

Note 10. Lease Commitments

The Company’s operating lease obligations, as defined and accounted for under legacy U.S. GAAP in effect as of December 31, 2018, primarily represent leases for surface use agreements, office buildings and equipment, communication towers, and field equipment. Lease payments associated with operating leases for the years ended December 31, 2018, 2017, and 2016 were $2.0 million, $1.9 million, and $4.4 million, respectively, a portion of which was capitalized and/or billed to other interest owners. At December 31, 2018, the minimum future rental commitments under operating leases having enforceable lease terms in excess of one year are reflected in the table below. Such commitments are reflected at undiscounted values and are not recognized on the Company's balance sheet at December 31, 2018.

In thousands	Total amount
2019	$1,535
2020	1,042
2021	833
2022	805

2023	745
Thereafter	6,795
Total obligations	$11,755

New lease accounting rules (ASU 2016-02) were adopted by the Company on January 1, 2019 that require enforceable long-term commitments under certain contracts which contain leases, as defined in ASU 2016-02, to be recognized on the Company's balance sheet at discounted present value. See Note 1. Organization and Summary of Significant Accounting Policies–New accounting pronouncements not yet adopted at December 31, 2018–Leases for further discussion.

Note 11. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2018. The commitments under these arrangements are not recorded in the accompanying consolidated balance sheets at December 31, 2018.

Drilling commitments – As of December 31, 2018, the Company has drilling rig contracts with various terms extending to February 2020 to ensure rig availability in its key operating areas. Future operating day-rate commitments as of December 31, 2018 total approximately $107 million, of which $106 million is expected to be incurred in 2019 and $1 million in 2020. A portion of these future costs will be borne by other interest owners. Such future commitments include minimum payment obligations to be incurred in 2019 and 2020 at a discounted present value totaling $13 million that qualify as leases and were recognized on the Company's balance sheet on January 1, 2019 upon adoption of ASU 2016-02 as discussed in Note 1. Organization and Summary of Significant Accounting Policies–New accounting pronouncements not yet adopted at December 31, 2018–Leases.

Transportation and processing commitments – The Company has entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. The commitments, which have varying terms extending as far as 2028, require the Company to pay per-unit transportation or processing charges regardless of the amount of capacity used. Future commitments remaining as of December 31, 2018 under the arrangements amount to approximately $1.83 billion, of which $241 million is expected to be incurred in 2019, $273 million in 2020, $254 million in 2021, $249 million in 2022, $248 million in 2023, and $566 million thereafter. A portion of these future costs will be borne by other interest owners. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. These commitments do not qualify as leases to be recognized on the balance sheet under ASU 2016-02 beginning January 1, 2019.

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition, as amended, alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and sought recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. The Company denied all allegations and denied that the case was properly brought as a class action. On June 11, 2015, the trial court certified a "hybrid" class requested by plaintiffs over the objections of the Company. The Company appealed the trial court's class certification order. On February 8, 2017, the Oklahoma Court of Civil Appeals reversed the trial court's ruling on certification and remanded the case for further proceedings. After certification of the case as a class action was reversed the parties engaged in settlement negotiations. Due to the uncertainty of and burdens of litigation, on February 16, 2018 the Company reached a settlement in connection with this matter. Under the settlement, the Company initially expected to make payments and incur costs associated with the settlement of approximately $59.6 million and accrued a loss for such amount at December 31, 2017. On April 3, 2018, the District Court of Garfield County, Oklahoma preliminarily approved the settlement and set certain dates applicable to the settlement including the timing and content of Notice, Opt-out, and Objections to Class Members. On June 12, 2018, the court entered an order formally approving the settlement, which is not subject to appeal. In the third quarter of 2018, the Company made payments totaling $45.8 million to satisfy the majority of its obligations under the settlement. The Company's remaining loss accrual for this matter totals $19.8 million at December 31, 2018, representing additional settlement obligations expected to be satisfied in 2019. The accrual for this matter is included in “Accrued liabilities and other” on the consolidated balance sheets.

The Company is involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. In addition to the accrued loss on the matter described above, as of December 31, 2018 and 2017 the Company had recorded a liability in the consolidated balance sheets under the caption “Other noncurrent liabilities” of $4.7 million and $7.6 million, respectively, for various matters, none of which are believed to be individually significant.

Environmental risk – Due to the nature of the crude oil and natural gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

Note 12. Related Party Transactions

Certain officers of the Company own or control entities that own working and royalty interests in wells operated by the Company. The Company paid revenues to these affiliates, including royalties, of $0.5 million, $0.5 million, and $0.4 million and received payments from these affiliates of $0.2 million, $0.3 million, and $0.3 million during the years ended December 31, 2018, 2017, and 2016, respectively, relating to the operations of the respective properties. At December 31, 2018 and 2017, approximately $67,000 and $58,000 was due from these affiliates, respectively, and approximately $41,000 and $48,000 was due to these affiliates, respectively, relating to these transactions.

The Company allows certain affiliates to use its corporate aircraft and crews and has used the aircraft of those same affiliates from time to time in order to facilitate efficient transportation of Company personnel. The rates charged between the parties vary by type of aircraft used. In 2016, the Company also purchased an existing prepaid maintenance account from an affiliate for use in major engine overhaul to be applied as needed for corporate aircrafts. For usage during 2018, 2017, and 2016, the Company charged affiliates approximately $12,900, $19,400, and $9,500, respectively, for use of its corporate aircraft crews, fuel, and reimbursement of expenses and received approximately $14,400, $18,600, and $6,800 from affiliates in 2018, 2017, and 2016, respectively. The Company was charged approximately $598,000, $460,000, and $292,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2018, 2017, and 2016 (including the aforementioned prepayment) and paid $529,000, $368,000, and $195,000 to the affiliates in 2018, 2017, and 2016, respectively. At December 31, 2018 and 2017, approximately $2,700 and $4,200 was due from an affiliate, respectively, and approximately $161,000 and $92,000 was due to an affiliate, respectively, relating to these transactions.

The Company capitalized costs of $0.1 million in 2016 associated with drilling rig services and demobilization of a drilling rig provided by an affiliate. The total amount paid to the affiliate, a portion of which was billed to other interest owners, was $0.1 million for the year ended December 31, 2016. No amounts were due to the affiliate at December 31, 2018 and 2017 related to the services.

Note 13. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2013 Long-Term Incentive Plan (“2013 Plan”) as discussed below. The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the consolidated statements of comprehensive income (loss), was $47.2 million, $45.9 million, and $48.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved 19,680,072 shares of common stock that may be issued pursuant to the plan. As of December 31, 2018, the Company had 13,736,734 shares of common stock available for long-term incentive awards to employees and directors under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company’s common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock and to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

A summary of changes in non-vested restricted shares from December 31, 2015 to December 31, 2018 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2015	3,249,611	$ 48.20
Granted	2,064,508	22.36
Vested	(1,207,235)	41.27
Forfeited	(193,250)	39.79
Non-vested restricted shares at December 31, 2016	3,913,634	$ 37.12
Granted	1,585,870	44.58
Vested	(874,665)	57.36
Forfeited	(598,729)	37.34
Non-vested restricted shares at December 31, 2017	4,026,110	$ 35.63
Granted	1,390,914	52.71
Vested	(1,116,329)	46.19
Forfeited	(278,286)	38.06
Non-vested restricted shares at December 31, 2018	4,022,409	$ 38.44

The grant date fair value of restricted stock represents the closing market price of the Company's common stock on the date of grant. Compensation expense for a restricted stock grant is determined at the grant date fair value and is recognized over the vesting period as services are rendered by employees and directors. The Company estimates the number of forfeitures expected to occur in determining the amount of stock-based compensation expense to recognize. There are no post-vesting restrictions related to the Company's restricted stock. The fair value at the vesting date of restricted stock that vested during 2018, 2017 and 2016 was approximately $61.0 million, $39.8 million and $30.0 million, respectively. As of December 31, 2018, there was approximately $70 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.0 year.

Note 14. Accumulated Other Comprehensive Income (Loss)

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive income (loss)" within shareholders' equity attributable to Continental Resources on the consolidated balance sheets and "Other comprehensive income, net of tax" in the consolidated statements of comprehensive income (loss). The following table summarizes the change in accumulated other comprehensive income (loss) for the years ended December 31, 2018, 2017, and 2016:

	Year ended December 31,		
In thousands	2018	2017	2016
Beginning accumulated other comprehensive income (loss), net of tax	$307	$(260)	$(3,354)
Foreign currency translation adjustments	108	567	3,094
Income taxes (1)	—	—	—
Other comprehensive income, net of tax	108	567	3,094
Ending accumulated other comprehensive income (loss), net of tax	$415	$307	$(260)

(1) A valuation allowance has been recognized against all deferred tax assets associated with losses generated by the Company's Canadian operations, thereby resulting in no income taxes on other comprehensive income.

Note 15. Noncontrolling Interests

Strategic mineral relationship

In October 2018, Continental entered into a strategic relationship with Franco-Nevada Corporation to acquire oil and gas mineral interests in the SCOOP and STACK plays through a newly-formed minerals subsidiary named The Mineral Resources Company II, LLC ("TMRC II"). At closing, Continental contributed most of its previously acquired mineral interests to TMRC II in exchange for a 50.1% ownership interest in the entity. Additionally, at closing Franco-Nevada paid $214.8 million to Continental for a 49.9% ownership interest in TMRC II and for funding of its share of certain mineral acquisition costs.

In accordance with the transaction terms, the parties have committed, subject to satisfaction of agreed upon acreage development thresholds, to spend a remaining aggregate total of approximately $309 million through year-end 2021 to acquire additional oil and gas mineral interests through TMRC II. Continental is to fund 20% of future mineral acquisitions and will be entitled to receive between 25% and 50% of total revenues generated by TMRC II based upon performance relative to certain predetermined production targets.

Continental holds a controlling financial interest in TMRC II. Accordingly, Continental has consolidated the financial results of the entity and has presented the portion of TMRC II's results attributable to Franco-Nevada as a noncontrolling interest in its consolidated financial statements. Subsequent to closing, Franco-Nevada made additional capital contributions to, and received revenue distributions from, TMRC II in 2018 and the portion of Continental's consolidated net assets attributable to Franco-Nevada totaled $266.8 million at December 31, 2018. Continental incurred $4.8 million of costs associated with this transaction, which were recognized as a reduction of "Additional paid-in capital" within shareholders’ equity attributable to Continental.

Joint ownership arrangement

In December 2018, Continental entered into an arrangement with a third party to jointly acquire parking facilities adjacent to the companies' corporate office buildings. The activities of the parking facilities, which are immaterial to Continental, are managed through a newly-formed entity named SFPG, LLC. Continental holds a 57.4% controlling financial interest in SFPG and, accordingly, has consolidated the financial results of the entity and has included the results attributable to the third party within noncontrolling interests in Continental's financial statements. The portion of Continental's consolidated net assets attributable to the third party's ownership interest in SFPG totaled $9.9 million at December 31, 2018.

Note 16. Property Dispositions

2018

During 2018, the Company sold non-strategic properties in various areas for cash proceeds totaling $54.5 million. The Company recognized pre-tax gains on the transactions totaling $16.7 million. The disposed properties represented an immaterial portion of the Company’s production and proved reserves.

2017

In October 2017, the Company sold non-core leasehold in the STACK play for cash proceeds totaling $63.5 million and recognized a $56.9 million pre-tax gain in 2017 associated with the transaction. The disposed properties represented an immaterial portion of the Company’s production and proved reserves.

In September 2017, the Company sold properties in the Arkoma Woodford area for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold and producing properties with production totaling approximately 1,700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax loss of $3.5 million in 2017. The disposed properties represented an immaterial portion of the Company’s proved reserves.

In September 2017, the Company sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.2 million pre-tax gain in 2017 associated with the transaction.

2016

In October 2016, the Company sold approximately 30,000 net acres of non-core leasehold in the SCOOP play for cash proceeds totaling $295.6 million. The leasehold included producing properties with production totaling approximately 700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax gain of $201.0 million. The disposed properties represented an immaterial portion of the Company's proved reserves.

In September 2016, the Company sold properties in North Dakota and Montana for cash proceeds totaling $214.8 million, with no gain or loss recognized. The sale included approximately 68,000 net acres of leasehold in North Dakota and approximately

12,000 net acres of leasehold in Montana. The sale also included producing properties with production totaling approximately 2,700 barrels of oil equivalent per day. The disposed properties represented an immaterial portion of the Company’s proved reserves.

In April 2016, the Company sold approximately 132,000 net acres of undeveloped leasehold in Wyoming for cash proceeds totaling $110.0 million. In connection with the transaction, the Company recognized a pre-tax gain of $96.9 million. The disposed properties had no production or proved reserves.

Note 17. Crude Oil and Natural Gas Property Information

The tables reflected below represent consolidated figures for the Company and its subsidiaries. In 2014, the Company initiated exploratory drilling activities in Canada. Through December 31, 2018, those drilling activities have not had a material impact on the Company’s total capital expenditures, production, and revenues. Accordingly, the results of operations, costs incurred, and capitalized costs associated with the Canadian operations have not been shown separately from the consolidated figures in the tables below. Additionally, results attributable to noncontrolling interests are immaterial and are not separately presented below.

The following table sets forth the Company’s consolidated results of operations from crude oil and natural gas producing activities for the years ended December 31, 2018, 2017 and 2016.

	Year ended December 31,		
In thousands	2018	2017	2016
Crude oil and natural gas sales (1)	$4,678,722	$2,982,966	$2,026,958
Production expenses	(390,423)	(324,214)	(289,289)
Production taxes	(353,140)	(208,278)	(142,388)
Transportation expenses (1)	(191,587)	—	—
Exploration expenses	(7,642)	(12,393)	(16,972)
Depreciation, depletion, amortization and accretion	(1,839,241)	(1,652,180)	(1,679,485)
Property impairments	(125,210)	(237,370)	(237,292)
Income tax (provision) benefit (2)	(434,047)	504,475	126,794
Results from crude oil and natural gas producing activities	$1,337,432	$1,053,006	$(211,674)

(1) For 2018, crude oil and natural gas sales are presented gross of certain transportation expenses as a result of the Company's January 1, 2018 adoption of new revenue recognition and presentation rules as discussed in Note 8. Revenues. The new rules were prospectively applied beginning January 1, 2018 and prior period results have not been adjusted to conform to the current presentation.

(2) Income taxes reflect the application of a combined federal and state tax rate of 24.5% for 2018 and 38% for both 2017 and 2016 on pre-tax income and losses generated by operations in the United States. Additionally, the 2017 period includes a $713.7 million income tax benefit recognized upon the Company’s remeasurement of its deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017. See Note 9. Income Taxes for further discussion.

Costs incurred in crude oil and natural gas activities

Costs incurred, both capitalized and expensed, in connection with the Company's consolidated crude oil and natural gas acquisition, exploration and development activities for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Year ended December 31,		
In thousands	2018	2017	2016
Property acquisition costs:			
Proved	$31,579	$8,446	$5,008
Unproved	329,586	220,875	149,962
Total property acquisition costs	361,165	229,321	154,970
Exploration Costs	81,015	123,461	182,355
Development Costs	2,478,327	1,695,954	767,148
Total	$2,920,507	$2,048,736	$1,104,473

Costs incurred above include asset retirement costs and revisions thereto of $25.8 million, $15.3 million and ($9.6) million for the years ended December 31, 2018, 2017 and 2016, respectively.

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company's consolidated crude oil and natural gas producing activities and related accumulated depreciation, depletion and amortization as of December 31, 2018 and 2017 are as follows:

	December 31,	
In thousands	2018	2017
Proved crude oil and natural gas properties	$24,060,625	$21,362,199
Unproved crude oil and natural gas properties	291,564	365,413
Total	24,352,189	21,727,612
Less accumulated depreciation, depletion and amortization	(10,680,870)	(8,971,935)
Net capitalized costs	$13,671,319	$12,755,677

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling and completion operations are complete, management attempts to determine whether the well has discovered crude oil and natural gas reserves and, if so, whether those reserves can be classified as proved reserves. Often, the determination of whether proved reserves can be recorded under SEC guidelines cannot be made when drilling is completed. In those situations where management believes that economically producible hydrocarbons have not been discovered, the exploratory drilling costs are reflected on the consolidated statements of comprehensive income (loss) as dry hole costs, a component of "Exploration expenses". Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred under the caption "Net property and equipment" on the consolidated balance sheets pending the outcome of those activities.

On at least a quarterly basis, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities—in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period of determination.

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The following table presents the amount of capitalized exploratory well costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended:

	Year ended December 31,		
In thousands	2018	2017	2016
Balance at January 1	$31,356	$34,852	$59,397
Additions to capitalized exploratory well costs pending determination of proved reserves	45,088	79,451	123,980
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(72,347)	(81,035)	(141,941)
Capitalized exploratory well costs charged to expense	(138)	(1,912)	(6,584)
Balance at December 31	$3,959	$31,356	$34,852
Number of gross wells	16	37	54

As of December 31, 2018, the Company had no significant exploratory well costs that were suspended one year beyond the completion of drilling.

Note 18. Supplemental Crude Oil and Natural Gas Information (Unaudited)

The table below shows estimates of proved reserves prepared by the Company’s internal technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company, L.P. prepared reserve estimates for properties comprising approximately 98%, 96%, and 99% of the Company's total proved reserves as of December 31, 2018, 2017, and 2016, respectively. Remaining reserve estimates were prepared by the Company’s internal technical staff. All proved reserves stated herein are located in the United States. No proved reserves have been included for the Company’s Canadian operations as of December 31, 2018, 2017, and 2016. Proved reserves attributable to noncontrolling interests are immaterial and are not separately presented in the tables below.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs 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 renewal is reasonably certain. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company’s might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions or removals of estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, changes in business strategies, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered.

Reserves at December 31, 2018, 2017 and 2016 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by SEC rules.

Natural gas imbalance receivables and payables for each of the three years ended December 31, 2018, 2017 and 2016 were not material and have not been included in the reserve estimates.

Proved crude oil and natural gas reserves

Changes in proved reserves were as follows for the periods presented:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved reserves as of December 31, 2015	700,514	3,151,786	1,225,811
Revisions of previous estimates	(99,966)	(63,057)	(110,474)
Extensions, discoveries and other additions	97,587	911,062	249,430
Production	(46,850)	(195,240)	(79,390)
Sales of minerals in place	(8,057)	(14,733)	(10,513)
Purchases of minerals in place	—	—	—
Proved reserves as of December 31, 2016	643,228	3,789,818	1,274,864
Revisions of previous estimates	(77,779)	(25,390)	(82,012)
Extensions, discoveries and other additions	129,895	661,867	240,206
Production	(50,536)	(228,159)	(88,562)
Sales of minerals in place	(4,365)	(64,989)	(15,197)
Purchases of minerals in place	506	7,134	1,696
Proved reserves as of December 31, 2017	640,949	4,140,281	1,330,995
Revisions of previous estimates	(76,994)	(1,153,555)	(269,253)
Extensions, discoveries and other additions	253,066	1,871,777	565,030
Production	(61,384)	(284,730)	(108,839)
Sales of minerals in place	(2,154)	(35,142)	(8,011)
Purchases of minerals in place	3,613	52,983	12,443
Proved reserves as of December 31, 2018	757,096	4,591,614	1,522,365

Revisions of previous estimates. Revisions for 2018 are comprised of (i) the removal of 74 MMBo and 960 Bcf (totaling 234 MMBoe) of PUD reserves no longer scheduled to be drilled within five years of initial booking due to the continual refinement of the Company's drilling programs and reallocation of capital to areas providing the greatest opportunities to improve efficiencies, recoveries, and rates of return, (ii) downward revisions of 21 MMBo and 216 Bcf (totaling 57 MMBoe) from the removal of PUD reserves due to changes in anticipated well densities and other factors, (iii) upward price revisions of 21 MMBo and 31 Bcf (totaling 26 MMBoe) due to an increase in average crude oil and natural gas prices in 2018 compared to 2017, and (iv) net downward revisions of 2 MMBo and 11 Bcf (totaling 4 MMBoe) due to changes in ownership interests, operating costs, anticipated production performance, and other factors.

Revisions for 2017 are comprised of (i) the removal of 89 MMBoe of PUD reserves not scheduled to be drilled within five years of initial booking due to changes in development plans, (ii) upward price revisions of 42 MMBoe due to an increase in average crude oil and natural gas prices in 2017 compared to 2016, (iii) downward revisions of 30 MMBoe due to changes in anticipated production performance, and (iv) net downward revisions of 5 MMBoe due to changes in ownership interests, operating costs, and other factors.

Revisions for 2016 are comprised of (i) the removal of 70 MMBoe of PUD reserves not scheduled to be drilled within five years of initial booking due to changes in development plans, (ii) downward price revisions of 28 MMBoe due to a decrease in average crude oil and natural gas prices in 2016 compared to 2015, and (iii) net downward revisions of 12 MMBoe due to changes in ownership interests, operating costs, anticipated production performance, and other factors.

Extensions, discoveries and other additions. Extensions, discoveries and other additions for each of the three years reflected in the table above were due to successful drilling and completion activities and continual refinement of our drilling programs in the Bakken, SCOOP, and STACK plays. For 2018, proved reserve additions in the Bakken totaled 176 MMBo and 448 Bcf (totaling 251 MMBoe) and reserve additions in SCOOP totaled 64 MMBo and 733 Bcf (totaling 186 MMBoe). Additionally, 2018 proved reserve additions in STACK totaled 13 MMBo and 691 Bcf (totaling 128 MMBoe).

Sales of minerals in place. See Note 16. Property Dispositions for a discussion of notable dispositions in 2016, 2017, and 2018, none of which involved significant volumes of proved reserves.

Purchases of minerals in place. There were no individually significant acquisitions of proved reserves in the three years reflected in the table above. The increase in acquired reserves in 2018 compared to prior years was due to higher mineral acquisition spending.

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped crude oil and natural gas reserves of the Company as of December 31, 2018, 2017 and 2016:

	December 31,		
	2018	2017	2016
Proved Developed Reserves			
Crude oil (MBbl)	347,825	318,707	290,210
Natural Gas (MMcf)	1,964,289	1,699,161	1,370,620
Total (MBoe)	675,206	601,901	518,646
Proved Undeveloped Reserves			
Crude oil (MBbl)	409,271	322,242	353,018
Natural Gas (MMcf)	2,627,325	2,441,120	2,419,198
Total (MBoe)	847,159	729,094	756,218
Total Proved Reserves			
Crude oil (MBbl)	757,096	640,949	643,228
Natural Gas (MMcf)	4,591,614	4,140,281	3,789,818
Total (MBoe)	1,522,365	1,330,995	1,274,864

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves expected to be recovered from new wells on undrilled acreage or from existing wells that require relatively major capital expenditures to recover, including most wells where drilling has occurred but the wells have not been completed. Natural gas is converted to barrels of crude oil equivalent using a conversion factor of six thousand cubic feet per barrel of crude oil based on the average equivalent energy content of natural gas compared to crude oil.

Standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using the 12-month unweighted average of the first-day-of-the-month commodity prices, the costs in effect at December 31 of each year and a 10% discount factor. The Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company’s estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the crude oil and natural gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, the estimated future net cash flow computations should not be considered to represent the Company’s estimate of the expected revenues or the current value of existing proved reserves.

The following table sets forth the standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves as of December 31, 2018, 2017 and 2016. Discounted future net cash flows attributable to noncontrolling interests are immaterial and are not separately presented below.

	December 31,		
In thousands	2018	2017	2016
Future cash inflows	$61,510,432	$42,574,897	$31,008,587
Future production costs	(16,139,001)	(11,159,362)	(9,175,410)
Future development and abandonment costs	(9,706,114)	(6,487,097)	(6,452,647)
Future income taxes (1)	(6,012,439)	(3,488,755)	(3,018,839)
Future net cash flows	29,652,878	21,439,683	12,361,691
10% annual discount for estimated timing of cash flows	(13,968,061)	(10,969,506)	(6,851,468)

Standardized measure of discounted future net cash flows	$15,684,817	$10,470,177	$5,510,223

(1) Estimated future income taxes were calculated by applying existing statutory tax rates, including any known future changes, to the estimated pre-tax net cash flows related to proved crude oil and natural gas reserves, giving effect to any permanent taxable differences and tax credits, less the tax basis of the properties involved. The U.S. federal statutory tax rate utilized in estimating future income taxes was 21% at December 31, 2018 and 2017 and 35% at December 31, 2016.

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $61.20, $47.03, and $35.57 per barrel at December 31, 2018, 2017 and 2016, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $3.22, $3.00, and $2.14 per Mcf at December 31, 2018, 2017 and 2016, respectively. Future cash flows are reduced by estimated future costs to develop and produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions. The expected tax benefits to be realized from the utilization of net operating loss carryforwards and tax credits are used in the computation of future income tax cash flows.

The changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are presented below for each of the past three years.

	December 31,		
In thousands	2018	2017	2016
Standardized measure of discounted future net cash flows at January 1	$10,470,177	$5,510,223	$6,476,284
Extensions, discoveries and improved recoveries, less related costs	5,162,635	1,462,629	786,587
Revisions of previous quantity estimates	(3,522,428)	(1,004,355)	(794,785)
Changes in estimated future development and abandonment costs	1,063,089	743,657	1,651,218
Sales of minerals in place, net	(9,192)	(41,077)	(90,390)
Net change in prices and production costs	4,224,473	3,808,116	(2,003,163)
Accretion of discount	1,183,347	665,507	798,597
Sales of crude oil and natural gas produced, net of production costs	(3,743,572)	(2,450,474)	(1,595,281)
Development costs incurred during the period	1,134,153	1,045,875	454,983
Change in timing of estimated future production and other	1,324,365	948,519	(538,665)
Change in income taxes	(1,602,230)	(218,443)	364,838
Net change	5,214,640	4,959,954	(966,061)
Standardized measure of discounted future net cash flows at December 31	$15,684,817	$10,470,177	$5,510,223

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Note 19. Quarterly Financial Data (Unaudited)

The Company’s unaudited quarterly financial data for 2018 and 2017 is summarized below.

	Quarter ended			
In thousands, except per share data	March 31	June 30	September 30	December 31
2018				
Total revenues (1)	$1,141,028	$1,137,113	$ 1,282,151	$ 1,149,294
Gain (loss) on natural gas derivatives, net (1)	$10,174	$(12,685)	$ (2,025)	$ (19,394)
Property impairments (2)	$33,784	$29,162	$ 23,770	$ 38,494
Gain on sale of assets, net (3)	$41	$6,710	$ 1,510	$ 8,410
Income from operations	$380,722	$391,276	$ 491,308	$ 330,414
Loss on extinguishment of debt (4)	$—	$—	$ (7,133)	$ —
Net income	$233,946	$242,464	$ 314,169	$ 199,121
Net income attributable to Continental Resources	$233,946	$242,464	$ 314,169	$ 197,738
Net income per share attributable to Continental Resources:				
Basic	$0.63	$0.65	$ 0.84	$ 0.53
Diluted	$0.63	$0.65	$ 0.84	$ 0.53
2017				
Total revenues (1)	$685,427	$661,486	$ 726,743	$ 1,047,172
Gain on natural gas derivatives, net (1)	$46,858	$28,022	$ 8,602	$ 8,165
Property impairments (2)	$51,372	$123,316	$ 35,130	$ 27,552
Litigation settlement (5)	$—	$—	$ —	$ 59,600
Gain (loss) on sale of assets, net (3)	$(3,638)	$780	$ 3,562	$ 54,420
Income (loss) from operations	$77,221	$(29,041)	$ 91,753	$ 309,468
Net income (loss) (6)	$469	$(63,557)	$ 10,621	$ 841,914
Net income (loss) per share:				
Basic	$—	$(0.17)	$ 0.03	$ 2.27
Diluted	$—	$(0.17)	$ 0.03	$ 2.25

(1) Gains and losses on natural gas derivative instruments are reflected in “Total revenues” on both the consolidated statements of comprehensive income (loss) and this table of unaudited quarterly financial data. Natural gas derivative gains and losses have been shown separately to illustrate the fluctuations in revenues that are attributable to the Company’s derivative instruments. Commodity price fluctuations each quarter can result in significant swings in mark-to-market gains and losses, which affects comparability between periods. Additionally, beginning in 2018 certain transportation expenses are no longer netted within "Total revenues" as a result of the Company's January 1, 2018 prospective adoption of ASU 2016-08, which affects comparability of 2017 and 2018 revenues. Transportation expenses totaled $49.3 million, $47.3 million, $46.0 million, and $49.0 million for the first, second, third, and fourth quarters of 2018, respectively.

(2) Property impairments have been shown separately to illustrate the impact on quarterly results attributable to write downs of the Company’s assets. Commodity price fluctuations each quarter can result in significant changes in estimated future cash flows and resulting impairments, which affects comparability between periods.

(3) Gains and losses on asset sales have been shown separately to illustrate the impact on quarterly results attributable to asset dispositions, which differ in significance from period to period and affect comparability. See Note 16. Property Dispositions for a discussion of notable dispositions.

(4) See Note 7. Long-Term Debt for discussion of the loss recognized by the Company upon the partial redemption of its 2022 Notes in the 2018 third quarter.

(5)

Fourth quarter 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Note 11. Commitments and Contingencies—Litigation, which resulted in an after-tax decrease in net income of $37.0 million ($0.10 per basic and diluted share).

(6) Fourth quarter 2017 results reflect the remeasurement of the Company's deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time decrease in income tax expense and corresponding increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share). See Note 9. Income Taxes for further discussion.

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

There have been no changes in accountants or any disagreements with accountants.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded the Company’s disclosure controls and procedures were effective as of December 31, 2018 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors during the fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our 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 our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our consolidated financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our consolidated 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.

Based on our evaluation under the framework in Internal Control—Integrated Framework (2013), the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ Harold G. Hamm
Chairman of the Board and Chief Executive Officer

/s/ John D. Hart
Senior Vice President, Chief Financial Officer and Treasurer

February 18, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated February 18, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's 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 included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 18, 2019

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held in May 2019 (the "Annual Meeting") and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information required by Item 201(d) of Regulation S-K with respect to securities authorized for issuance under equity compensation plans is disclosed in Part II, Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Equity Compensation Plan Information and is incorporated herein by reference. Other applicable information required as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The consolidated financial statements of Continental Resources, Inc. and Subsidiaries and the Report of Independent Registered Public Accounting Firm are included in Part II, Item 8 of this report. Reference is made to the accompanying Index to Consolidated Financial Statements.

(2) Financial Statement Schedules

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

(3) Index to Exhibits

The exhibits required to be filed or furnished pursuant to Item 601 of Regulation S-K are set forth below.

3.1	Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarter ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company's Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
4.1	Registration Rights Agreement dated as of May 18, 2007 by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust filed as Exhibit 4.1 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference.
4.2	Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
4.3	Indenture dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.2 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference.
4.4	Registration Rights Agreement dated as of August 13, 2012 among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, and Jeffrey B. Hume filed as Exhibit 4.6 to the Company's Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
4.5	Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Form 10-Q for the quarter ended March 31, 2018 (Commission File No. 001-32886) filed May 2, 2018 and incorporated herein by reference.
4.6	Indenture dated as of May 19, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2014 and incorporated herein by reference.

4.7	Indenture dated as of December 8, 2017 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 12, 2017 and incorporated herein by reference.
10.1†	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

10.2†	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.3†	Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended March 31, 2018 (Commission File No. 001-32886) filed May 2, 2018 and incorporated herein by reference.
10.4†	Form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended June 30, 2018 (Commission File No. 001-32886) filed August 7, 2018 and incorporated herein by reference.
10.5†	Form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.3 to the Company's Form 10-Q for the quarter ended June 30, 2018 (Commission File No. 001-32886) filed August 7, 2018 and incorporated herein by reference.
10.6†	Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended September 30, 2018 (Commission File No. 001-32886) filed October 29, 2018 and incorporated herein by reference.
10.7†	First Amendment to the Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2014 (Commission File No. 001-32886) filed May 8, 2014 and incorporated herein by reference.
10.8†	Second Amendment to the Continental Resources, Inc. Deferred Compensation Plan adopted and effective as of May 23, 2014 filed as Exhibit 10.15 to the Company's Registration Statement on Form S-4 (Commission File No. 333-196944) filed June 20, 2014 and incorporated herein by reference.
10.9	Revolving Credit Agreement dated as of April 9, 2018 among Continental Resources, Inc., as borrower, and its subsidiaries Banner Pipeline Company L.L.C., CLR Asset Holdings, LLC and The Mineral Resources Company as guarantors, MUFG Union Bank, N.A., as Administrative Agent, MUFG Union Bank, N.A., Merrill Lynch, Pierce, Fenner & Smith Incorporated, TD Securities (USA) LLC and Mizuho Bank, Ltd., as Joint Lead Arrangers and Joint Bookrunners, Compass Bank, Citibank, N.A., Export Development Canada, ING Bank, JPMorgan Chase Bank, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A., as Co-Documentation Agents and the other lenders named therein filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 12, 2018 and incorporated herein by reference.
10.10†	Summary of Non-Employee Director Compensation approved as of May 16, 2018 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended June 30, 2018 (Commission File No. 001-32886) filed August 7, 2018 and incorporated herein by reference.
10.11†	Description of cash bonus plan updated as of August 3, 2018 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended September 30, 2018 (Commission File No. 001-32886) filed October 29, 2018 and incorporated herein by reference.
21*	Subsidiaries of Continental Resources, Inc.

23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)
32**	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
99*	Report of Ryder Scott Company, L.P., Independent Petroleum Engineers and Geologists
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document

101.CAL** XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF** XBRL Taxonomy Extension Definition Linkbase Document

101.LAB** XBRL Taxonomy Extension Label Linkbase Document

101.PRE** XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith
† Management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Signatures

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

CONTINENTAL RESOURCES, INC.

By: /S/ HAROLD G. HAMM
Name: Harold G. Hamm
Title: Chairman of the Board and Chief Executive Officer
Date: February 18, 2019

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

Signature	Title	Date
/s/ HAROLD G. HAMM Harold G. Hamm	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 18, 2019
/s/ JOHN D. HART John D. Hart	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 18, 2019
/s/ WILLIAM B. BERRY William B. Berry	Director	February 18, 2019
/s/ SHELLY LAMBERTZ Shelly Lambertz	Director	February 18, 2019
/s/ LON MCCAIN Lon McCain	Director	February 18, 2019
/s/ JOHN T. MCNABB II John T. McNabb II	Director	February 18, 2019
/s/ MARK E. MONROE Mark E. Monroe	Director	February 18, 2019