CONTINENTAL RESOURCES, INC
Form 10-Q
April 29, 2019
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2019
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 of incorporation or organization)	(I.R.S. Employer Identification No.)
20 N. Broadway, Oklahoma City, Oklahoma	73102
(Address of principal executive offices)	(Zip Code)

(405) 234-9000
(Registrant's telephone number, including area code)
Not Applicable
(Former name, former address and former fiscal year, if changed since last report)
Securities registered pursuant to Section 12(b) of the Act:

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

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 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 Exchange Act). Yes ¨ No x

376,745,750 shares of our $0.01 par value common stock were outstanding on April 22, 2019.

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When we refer to “us,” “we,” “our,” “Company,” or “Continental” we are describing Continental Resources, Inc. and our subsidiaries.

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:
“Bbl” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.
“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.
“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.
“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.
"gross acres" or "gross wells" Refers to the total acres or wells in which a working interest is owned.
“MBbl” One thousand barrels of crude oil, condensate or natural gas liquids.
“MBoe” One thousand Boe.
“Mcf” One thousand cubic feet of natural gas.
“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 presented herein are non-GAAP measures. See Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of this 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. 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 presented herein are non-GAAP measures. See Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for a discussion and calculation of this measure.
“NYMEX” The New York Mercantile Exchange.

“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.

“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.

“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.

“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.

“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.

“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,” “target,” “plan,” “continue,” “potential,” “g and similar 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 II, Item 1A. Risk Factors and elsewhere in this report, if any, our Annual Report on Form 10-K for the year ended December 31, 2018, 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 or our Annual

Report on Form 10-K 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. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets

In thousands, except par values and share data	March 31, 2019 (Unaudited)	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$264,371	$282,749
Receivables:		
Crude oil and natural gas sales	698,641	644,107
Affiliated parties	74	73
Joint interest and other, net	395,657	368,235
Derivative assets	1,975	15,612
Inventories	103,287	88,544
Prepaid expenses and other	20,057	13,041
Total current assets	1,484,062	1,412,361
Net property and equipment, based on successful efforts method of accounting	14,118,264	13,869,800
Operating lease right-of-use assets	16,099	—
Other noncurrent assets	15,498	15,786
Total assets	$15,633,923	$15,297,947
Liabilities and equity		
Current liabilities:		
Accounts payable trade	$755,834	$717,560
Revenues and royalties payable	406,832	400,567
Payables to affiliated parties	259	203
Accrued liabilities and other	268,507	266,819
Derivative liabilities	549	—
Current portion of operating lease liabilities	11,092	—
Current portion of long-term debt	2,378	2,360
Total current liabilities	1,445,451	1,387,509
Long-term debt, net of current portion	5,766,647	5,765,989
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,626,426	1,574,436
Asset retirement obligations, net of current portion	141,172	136,986
Operating lease liabilities, net of current portion	5,007	—
Other noncurrent liabilities	10,917	11,166
Total other noncurrent liabilities	1,783,522	1,722,588
Commitments and contingencies (Note 9)		
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; 376,768,684 shares issued and outstanding at March 31, 2019; 376,021,575 shares issued and outstanding at December 31, 2018	3,768	3,760
Additional paid-in capital	1,426,300	1,434,823
Accumulated other comprehensive income	531	415
Retained earnings	4,893,111	4,706,135

Total shareholders' equity attributable to Continental Resources	6,323,710	6,145,133
Noncontrolling interests	314,593	276,728
Total equity	6,638,303	6,421,861
Total liabilities and equity	$15,633,923	$15,297,947

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

1

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Comprehensive Income

	Three months ended March 31,	
In thousands, except per share data	2019	2018
Revenues:		
Crude oil and natural gas sales	$1,109,584	$1,113,852
Gain (loss) on natural gas derivatives, net	(1,124)	10,174
Crude oil and natural gas service operations	15,774	17,002
Total revenues	1,124,234	1,141,028
Operating costs and expenses:		
Production expenses	106,966	92,962
Production taxes	86,441	80,580
Transportation expenses	49,139	49,297
Exploration expenses	1,837	1,720
Crude oil and natural gas service operations	7,186	4,583
Depreciation, depletion, amortization and accretion	495,019	454,378
Property impairments	25,316	33,784
General and administrative expenses	47,617	43,043
Net gain on sale of assets and other	(252)	(41)
Total operating costs and expenses	819,269	760,306
Income from operations	304,965	380,722
Other income (expense):		
Interest expense	(67,837)	(75,894)
Other	1,355	654
	(66,482)	(75,240)
Income before income taxes	238,483	305,482
Provision for income taxes	(51,990)	(71,536)
Net income	186,493	233,946
Net loss attributable to noncontrolling interests	(483)	—
Net income attributable to Continental Resources	$186,976	$233,946
Net income per share attributable to Continental Resources:		
Basic	$0.50	$0.63
Diluted	$0.50	$0.63
Comprehensive income:		
Net income	$186,493	$233,946
Other comprehensive income, net of tax:		
Foreign currency translation adjustments	116	2
Total other comprehensive income, net of tax	116	2
Comprehensive income	186,609	233,948
Comprehensive loss attributable to noncontrolling interests	(483)	—
Comprehensive income attributable to Continental Resources	$187,092	$233,948

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

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Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statements of Equity

Three months ended March 31, 2019	Shareholders' equity attributable to Continental Resources							
In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
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
Net income (loss) (unaudited)	—	—	—	—	186,976	186,976	(483)	186,493
Other comprehensive income, net of tax (unaudited)	—	—	—	116	—	116	—	116
Stock-based compensation (unaudited)	—	—	12,095	—	—	12,095	—	12,095
Restricted stock:								
Granted (unaudited)	1,333,602	13	—	—	—	13	—	13
Repurchased and canceled (unaudited)	(439,419)	(4)	(20,618)	—	—	(20,622)	—	(20,622)
Forfeited (unaudited)	(147,074)	(1)	—	—	—	(1)	—	(1)
Contributions from noncontrolling interests (unaudited)	—	—	—	—	—	—	42,204	42,204
Distributions to noncontrolling interests (unaudited)	—	—	—	—	—	—	(3,856)	(3,856)
Balance at March 31, 2019 (unaudited)	376,768,684	$3,768	$1,426,300	$ 531	$4,893,111	$6,323,710	$314,593	$6,638,303

Three months ended March 31, 2018	Shareholders' equity attributable to Continental Resources							
In thousands, except share data	Shares outstanding	Common stock	Additional paid-in	Accumulated other	Retained earnings	Total shareholders'	Noncontrolling interests	Total equity

			capital	comprehensive income		equity of Continental Resources		
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 (unaudited)	—	—	—	—	233,946	233,946	—	233,946
Other comprehensive income, net of tax (unaudited)	—	—	—	2	—	2	—	2
Stock-based compensation (unaudited)	—	—	10,905	—	—	10,905	—	10,905
Restricted stock:								
Granted (unaudited)	1,180,032	12	—	—	—	12	—	12
Repurchased and canceled (unaudited)	(276,108)	(3)	(14,843)	—	—	(14,846)	—	(14,846)
Forfeited (unaudited)	(66,489)	(1)	—	—	—	(1)	—	(1)
Balance at March 31, 2018 (unaudited)	376,057,204	$3,760	$1,405,388	$ 309	$3,951,764	$5,361,221	$ —	$5,361,221

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

	Three months ended March 31,	
In thousands	2019	2018
Cash flows from operating activities		
Net income	$186,493	$233,946
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	496,561	455,559
Property impairments	25,316	33,784
Non-cash (gain) loss on derivatives, net	14,186	(5,978)
Stock-based compensation	12,107	10,916
Provision for deferred income taxes	51,990	71,536
Gain on sale of assets, net	(252)	(41)
Other, net	3,683	3,398
Changes in assets and liabilities:		
Accounts receivable	(78,027)	38,268
Inventories	(14,742)	(9,763)
Other current assets	(5,786)	(6,343)
Accounts payable trade	24,341	48,307
Revenues and royalties payable	6,282	18,541
Accrued liabilities and other	(563)	(5,848)
Other noncurrent assets and liabilities	(81)	(91)
Net cash provided by operating activities	721,508	886,191
Cash flows from investing activities		
Exploration and development	(732,770)	(618,200)
Purchase of producing crude oil and natural gas properties	(15,849)	(2,647)
Purchase of other property and equipment	(4,951)	(7,421)
Proceeds from sale of assets	499	57
Net cash used in investing activities	(753,071)	(628,211)
Cash flows from financing activities		
Credit facility borrowings	100,000	370,000
Repayment of credit facility	(100,000)	(558,000)
Repayment of other debt	(576)	(566)
Debt issuance costs	—	(312)
Contributions from noncontrolling interests	38,242	—
Distributions to noncontrolling interests	(3,874)	—
Repurchase of restricted stock for tax withholdings	(20,622)	(14,846)
Net cash (used in) provided by financing activities	13,170	(203,724)
Effect of exchange rate changes on cash	15	(13)
Net change in cash and cash equivalents	(18,378)	54,243
Cash and cash equivalents at beginning of period	282,749	43,902
Cash and cash equivalents at end of period	$264,371	$98,145

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Continental Resources, Inc. (the "Company") was 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.

A majority of the Company's operations are located in the North region, with that region comprising 63% of the Company's crude oil and natural gas production and 75% of its crude oil and natural gas revenues for the three months ended March 31, 2019. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. The Company's operations in the South region continue to expand with its increased activity in the SCOOP and STACK plays and that region comprised 37% of the Company's crude oil and natural gas production and 25% of its crude oil and natural gas revenues for the three months ended March 31, 2019.

For the three months ended March 31, 2019, crude oil accounted for 58% of the Company's total production and 82% of its crude oil and natural gas revenues.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The condensed 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.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States ("U.S. GAAP"), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Quarterly Report on Form 10-Q ("Form 10-Q") together with the Company's Annual Report on Form 10-K for the year ended December 31, 2018 ("2018 Form 10-K"), which includes a summary of the Company's significant accounting policies and other disclosures.

The condensed consolidated financial statements as of March 31, 2019 and for the three month periods ended March 31, 2019 and 2018 are unaudited. The condensed consolidated balance sheet as of December 31, 2018 was derived from the audited balance sheet included in the 2018 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these condensed consolidated financial statements.

The preparation of financial statements in conformity with 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. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these unaudited condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations that may be expected for any other interim period or for an entire year.

Earnings per share

Basic net income per share is computed by dividing net income 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

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

table presents the calculation of basic and diluted weighted average shares outstanding and net income per share attributable to the Company for the three months ended March 31, 2019 and 2018.

	Three months ended March 31,	
In thousands, except per share data	2019	2018
Net income attributable to Continental Resources (numerator)	$186,976	$233,946
Weighted average shares (denominator):		
Weighted average shares - basic	372,563	371,543
Non-vested restricted stock	1,911	2,638
Weighted average shares - diluted	374,474	374,181
Net income per share attributable to Continental Resources:		
Basic	$0.50	$0.63
Diluted	$0.50	$0.63

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 March 31, 2019 and December 31, 2018 consisted of the following:

In thousands	March 31, 2019	December 31, 2018
Tubular goods and equipment	$14,794	$ 14,623
Crude oil	88,493	73,921
Total	$103,287	$ 88,544

Adoption of new accounting pronouncement

On January 1, 2019 the Company adopted Accounting Standards Update ("ASU") 2016-02, Leases (Topic 842). See Note 8. Leases for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New accounting pronouncement not yet adopted

In June 2016 the Financial Accounting Standards Board ("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.

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

Note 3. 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.

In thousands	Three months ended March 31, 2019	2018
Supplemental cash flow information:		
Cash paid for interest	$61,964	$52,251
Cash paid for income taxes	9	—
Cash received for income tax refunds	4	5
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	2,570	1,609

As of March 31, 2019 and December 31, 2018, the Company had $329.6 million and $317.5 million, respectively, of accrued capital expenditures included in “Net property and equipment” and “Accounts payable trade” in the condensed consolidated balance sheets.

As of March 31, 2019 and December 31, 2018, the Company had $13.2 million and $9.3 million, respectively, of accrued contributions from noncontrolling interests included in "Receivables–Joint interest and other, net" and "Equity–Noncontrolling interests" in the condensed consolidated balance sheets.

As of March 31, 2019 and December 31, 2018, the Company had $1.3 million and $1.3 million, respectively, of accrued distributions to noncontrolling interests included in "Revenues and royalties payable" and "Equity–Noncontrolling interests" in the condensed consolidated balance sheets.

On January 1, 2019 the Company adopted ASU 2016-02 which resulted in the non-cash recognition of offsetting right-of-use assets and lease liabilities totaling approximately $19 million. See Note 8. Leases for additional information.

Note 4. Revenues

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 are presented separately from transportation expenses 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 $41.6 million and $40.4 million for the three months ended March 31, 2019 and 2018, respectively.

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. The Company currently takes certain processed residue gas volumes in kind in lieu of monetary

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settlement, but does not take NGL volumes. 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 $7.5 million and $8.9 million for the three months ended March 31, 2019 and 2018, respectively, 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 three months ended March 31, 2019 and 2018.

	Three months ended March 31, 2019			Three months ended March 31, 2018		
In thousands	North Region	South Region	Total	North Region	South Region	Total
Crude oil revenues:						
Operated properties	$585,605	$136,547	$722,152	$569,211	$138,453	$707,664
Non-operated properties	178,728	10,238	188,966	182,887	15,730	198,617
Total crude oil revenues	764,333	146,785	911,118	752,098	154,183	906,281
Natural gas revenues:						
Operated properties	51,461	124,698	176,159	51,820	127,254	179,074
Non-operated properties	10,866	11,441	22,307	13,680	14,817	28,497
Total natural gas revenues	62,327	136,139	198,466	65,500	142,071	207,571
Crude oil and natural gas sales	$826,660	$282,924	$1,109,584	$817,598	$296,254	$1,113,852
Timing of revenue recognition						
Goods transferred at a point in time	$826,660	$282,924	$1,109,584	$817,598	$296,254	$1,113,852
Goods transferred over time	—	—	—	—	—	—
	$826,660	$282,924	$1,109,584	$817,598	$296,254	$1,113,852

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 March 31, 2019 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 the Company's 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 condensed 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 three months ended March 31, 2019 and 2018 related to performance obligations satisfied in prior reporting periods were not material.

Note 5. Derivative Instruments

Natural gas derivatives

From time to time the Company has entered into natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of natural gas production. The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its derivatives 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 unaudited condensed consolidated statements of comprehensive income under the caption “Gain (loss) on 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, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars 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.

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At March 31, 2019 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 period. At March 31, 2019 the Company had no outstanding crude oil derivative contracts.

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
April 2019 - December 2019		
Swaps - Henry Hub	158,675,000	$ 2.80

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.

	Three months ended March 31,	
In thousands	2019	2018
Cash received on derivatives:		
Natural gas fixed price swaps	$7,645	$4,196
Natural gas collars	5,417	—
Cash received on derivatives, net	13,062	4,196
Non-cash gain (loss) on derivatives:		
Natural gas fixed price swaps	(8,704)	5,978
Natural gas collars	(5,482)	—
Non-cash gain (loss) on derivatives, net	(14,186)	5,978
Gain (loss) on natural gas derivatives, net	$(1,124)	$10,174

Balance sheet offsetting of derivative assets and liabilities

The Company’s derivative contracts are recorded at fair value in the condensed 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 condensed 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 condensed consolidated balance sheets for the periods presented, all at fair value.

In thousands	March 31, 2019	December 31, 2018
Commodity derivative assets:		
Gross amounts of recognized assets	$4,622	$16,789
Gross amounts offset on balance sheet	(2,647)	(1,177)
Net amounts of assets on balance sheet	1,975	15,612
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(3,196)	(1,177)
Gross amounts offset on balance sheet	2,647	1,177
Net amounts of liabilities on balance sheet	$(549)	$—

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

In thousands	March 31, 2019	December 31, 2018
Derivative assets	$ 1,975	$ 15,612
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	1,975	15,612
Derivative liabilities	(549)	—
Noncurrent derivative liabilities	—	—
Net amounts of liabilities on balance sheet	(549)	—
Total derivative assets, net	$ 1,426	$ 15,612

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.

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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 March 31, 2019 and December 31, 2018.

	Fair value measurements at March 31, 2019 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$ 1,426	$ —	$ 1,426
Total	$ —	$ 1,426	$ —	$ 1,426

	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

Assets Measured at Fair Value on a Nonrecurring Basis

Certain assets are reported at fair value on a nonrecurring basis in the condensed 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 March 31, 2019 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 three months ended March 31, 2019 and 2018, estimated future net cash flows were determined to be in excess of cost basis, therefore no impairment was recorded for the Company's proved crude oil and natural gas properties for those periods.

Certain unproved crude oil and natural gas properties were impaired during the three months ended March 31, 2019 and 2018, 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.

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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 unaudited condensed consolidated statements of comprehensive income.

	Three months ended March 31,	
In thousands	2019	2018
Proved property impairments	$—	$—
Unproved property impairments	25,316	33,784
Total	$25,316	$33,784

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 condensed consolidated financial statements.

	March 31, 2019		December 31, 2018	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Credit facility	$—	$—	$—	$—
Note payable	7,119	7,100	7,700	7,700
5% Senior Notes due 2022	1,598,496	1,611,700	1,598,404	1,590,900
4.5% Senior Notes due 2023	1,489,536	1,550,900	1,488,960	1,476,300
3.8% Senior Notes due 2024	993,436	1,007,500	993,151	947,200
4.375% Senior Notes due 2028	988,879	1,027,800	988,617	942,800
4.9% Senior Notes due 2044	691,559	710,400	691,517	618,800
Total debt	$5,769,025	$5,915,400	$5,768,349	$5,583,700

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.

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Note 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $38.1 million and $39.4 million at March 31, 2019 and December 31, 2018, respectively, consists of the following.

In thousands	March 31, 2019	December 31, 2018
Credit facility	$—	$ —
Note payable	7,119	7,700
5% Senior Notes due 2022	1,598,496	1,598,404
4.5% Senior Notes due 2023	1,489,536	1,488,960
3.8% Senior Notes due 2024	993,436	993,151
4.375% Senior Notes due 2028	988,879	988,617
4.9% Senior Notes due 2044	691,559	691,517
Total debt	$5,769,025	$ 5,768,349
Less: Current portion of long-term debt	2,378	2,360
Long-term debt, net of current portion	$5,766,647	$ 5,765,989

Credit Facility

The Company has an unsecured credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion. The Company had no outstanding borrowings on its credit facility at March 31, 2019 and 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.

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 March 31, 2019.

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 March 31, 2019.

	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 March 31, 2019.

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.

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 condensed consolidated balance sheets as of March 31, 2019.

Note 8. 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 twelve 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 right-of-use assets and lease liabilities recognized by the Company on the January 1, 2019 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. No cumulative-effect adjustment to retained earnings was recognized upon adoption of the new standard.

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 ASC Topic 842 to leases with durations of twelve months or less and has elected to use hindsight in determining the lease term for all leases. The Company's leasing activities as a lessor are negligible.

Presented below are disclosures required by the new lease standard. The amounts disclosed herein primarily represent costs associated with properties operated by the Company that are presented on a gross basis and do not reflect the Company's net proportionate share of such amounts. A portion of these costs have been or will be billed to other working interest owners. Once paid, the Company's share of these costs are included in property and equipment, production expenses, or general and administrative expenses, as applicable.

The Company’s lease liabilities recognized on the balance sheet as a lessee totaled $16.1 million as of March 31, 2019 at discounted present value, which is comprised of the asset classes reflected in the table below. All leases recognized on the Company's balance sheet are classified as operating leases.

In thousands	Amount
Drilling rig commitments	$10,543
Surface use agreements	3,791
Field equipment	1,384
Other	381
Total	$16,099

Drilling rig commitments reflected above represent minimum payment obligations expected to be incurred through February 2020 on enforceable commitments with durations in excess of one year beyond January 1, 2019.

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Minimum future commitments by year for the Company's operating leases as of March 31, 2019 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the balance sheet.

In thousands	Amount
Remainder of 2019	$9,819
2020	2,300
2021	706
2022	691
2023	624
Thereafter	4,872
Total operating lease liabilities, at undiscounted value	$19,012
Less: Imputed interest	(2,913)
Total operating lease liabilities, at discounted present value	$16,099
Less: Current portion of operating lease liabilities	(11,092)
Operating lease liabilities, net of current portion	$5,007

Additional information for the Company's operating leases is presented below. Lease costs are reflected at gross amounts and primarily represent costs incurred for drilling rigs, most of which are short term contracts that are not recognized as right-of-use assets and lease liabilities on the balance sheet. Variable lease costs primarily represent differences between minimum payment obligations and actual operating day-rate charges incurred by the Company for its long term drilling rig contracts.

In thousands, except weighted average data	Three months ended March 31, 2019
Lease costs:	
Operating lease costs	$3,273
Variable lease costs	3,122
Short-term lease costs	55,161
Total lease costs	$61,556
Other information:	
Operating cash flows from operating leases included in lease liabilities	$199
Weighted average remaining lease term	5.9 years
Weighted average discount rate	4.7 %

Note 9. Commitments and Contingencies

Included below is a discussion of certain future commitments and contingencies of the Company as of March 31, 2019.

Drilling rig commitments – As of March 31, 2019, 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 March 31, 2019 total approximately $83 million, of which $82 million is expected to be incurred in the remainder of 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 through February 2020 with a discounted present value totaling $10.5 million that are required to be recognized on the Company's balance sheet at March 31, 2019 in accordance with ASC Topic 842 as discussed in Note 8. Leases.

Other lease commitments – The Company has various other lease commitments primarily associated with surface use agreements and field equipment. See Note 8. Leases for additional information.

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 March 31, 2019 under the arrangements amount to approximately $1.74 billion, of which $182 million is expected to be incurred in the remainder of 2019, $269 million in 2020, $250 million in 2021, $245 million in 2022, $245 million in 2023, and $551 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 under ASC Topic 842 and are not recognized on the Company's balance sheet.

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. Due to the uncertainty of and burdens of litigation, in February 2018 the Company reached a settlement in connection with this matter, which was subsequently approved by the District Court of Garfield County, Oklahoma in June 2018. 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. 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 $21.1 million at March 31, 2019, representing additional settlement obligations expected to be satisfied in the third quarter of 2019. The accrual for this matter is included in “Accrued liabilities and other” on the condensed 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 March 31, 2019 and December 31, 2018 the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $4.5 million and $4.7 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 10. 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 unaudited condensed consolidated statements of comprehensive income, was $12.1 million and $10.9 million for the three months ended March 31, 2019 and 2018, 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 March 31, 2019, the Company had 12,989,625 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 outstanding for the three months ended March 31, 2019 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2018	4,022,409	$ 38.44
Granted	1,333,602	44.32
Vested	(1,566,904)	21.65
Forfeited	(147,074)	46.85
Non-vested restricted shares outstanding at March 31, 2019	3,642,033	$ 47.48

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 the three months ended March 31, 2019 was approximately $74 million. As of March 31, 2019, there was approximately $110 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.9 years.

Note 11. Accumulated Other Comprehensive Income

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in “Accumulated other comprehensive income” within shareholders’ equity attributable to Continental Resources on the condensed consolidated balance sheets and “Other comprehensive income, net of tax” in the unaudited condensed consolidated statements of comprehensive income. The following table summarizes the change in accumulated other comprehensive income for the three months ended March 31, 2019 and 2018:

	Three months ended March 31,	
In thousands	2019	2018
Beginning accumulated other comprehensive income, net of tax	$415	$307
Foreign currency translation adjustments	116	2
Income taxes (1)	—	—
Other comprehensive income, net of tax	116	2
Ending accumulated other comprehensive income, net of tax	$531	$309

(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 12. 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 period-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.

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The Company's provision for income taxes totaled $52.0 million and $71.5 million for the three months ended March 31, 2019 and 2018, respectively. These amounts differ from the amounts computed by applying the United States statutory federal income tax rate to net income before income taxes. The sources and tax effects of the differences are reflected in the table below:

	Three months ended March 31,			
$ in thousands	2019	Tax rate %	2018	Tax rate %
Expected income tax provision based on US statutory tax rate	$(50,081)	21.0%	$(64,151)	21.0%
State income taxes, net of federal benefit	(7,798)	3.3 %	(9,164)	3.0 %
Tax benefit from stock-based compensation	8,318	(3.5 %)	1,509	(0.5 %)
Other, net	(2,429)	1.0 %	270	(0.1 %)
Provision for income taxes	$(51,990)	21.8%	$(71,536)	23.4%

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Form 10-K for the year ended December 31, 2018. Our operating results for the periods discussed below may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described in Part II, Item 1A. Risk Factors included in this report, if any, and in our Form 10-K for the year ended December 31, 2018, 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.

First Quarter 2019 Highlights

- Total production for the first quarter of 2019 averaged 332,236 Boe per day, up 3% sequentially from the fourth quarter of 2018 and 16% higher than the first quarter of 2018.
- Average daily crude oil production increased 4% over the 2018 fourth quarter and 18% over the 2018 first quarter driven by strong production growth in the Bakken field and Project SpringBoard play in SCOOP.
- Bakken average daily crude oil production increased 8% over the 2018 fourth quarter and 22% over the 2018 first quarter.
- Crude oil sales price differentials improved significantly from late 2018 levels to $4.77 per barrel for the 2019 first quarter compared to $8.44 per barrel for the 2018 fourth quarter.
- Maintained low per-unit production expenses through the winter months at $3.59 per Boe for the 2019 first quarter.
- Debt reduction over the past year generated an $8.1 million, or 11%, decrease in interest expense in the 2019 first quarter compared to the 2018 first quarter.

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.

	Three months ended March 31, 2019	2018
Average daily production:		
Crude oil (Bbl per day)	193,921	163,837
Natural gas (Mcf per day)	829,891	741,442
Crude oil equivalents (Boe per day)	332,236	287,410
Average net sales prices (1):		
Crude oil ($/Bbl)	$50.05	$58.98
Natural gas ($/Mcf)	$2.56	$2.98
Crude oil equivalents ($/Boe)	$35.56	$41.26
Crude oil net sales price discount to NYMEX ($/Bbl)	$(4.77)	$(3.91)
Natural gas net sales price discount to NYMEX ($/Mcf)	$(0.60)	$—
Production expenses ($/Boe)	$3.59	$3.60
Production taxes (% of net crude oil and natural gas sales)	8.2 %	7.6 %
Depreciation, depletion, amortization and accretion ($/Boe)	$16.60	$17.61
Total general and administrative expenses ($/Boe)	$1.60	$1.67

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

Three months ended March 31, 2019 compared to the three months ended March 31, 2018

Results of Operations

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

In thousands	Three months ended March 31, 2019	2018
Crude oil and natural gas sales	$1,109,584	$1,113,852
Gain (loss) on natural gas derivatives, net	(1,124)	10,174
Crude oil and natural gas service operations	15,774	17,002
Total revenues	1,124,234	1,141,028
Operating costs and expenses	(819,269)	(760,306)
Other expenses, net	(66,482)	(75,240)
Income before income taxes	238,483	305,482
Provision for income taxes	(51,990)	(71,536)
Net income	$186,493	$233,946
Production volumes:		
Crude oil (MBbl)	17,453	14,745
Natural gas (MMcf)	74,690	66,730
Crude oil equivalents (MBoe)	29,901	25,867
Sales volumes:		
Crude oil (MBbl)	17,373	14,682
Natural gas (MMcf)	74,690	66,730
Crude oil equivalents (MBoe)	29,821	25,804

Production

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

Boe production per day	1Q 2019	1Q 2018	% Change from 1Q 2018	4Q 2018	% Change from 4Q 2018
Bakken	199,423	161,356	24 %	183,836	8 %
SCOOP	67,659	62,012	9 %	67,244	1 %
STACK	56,513	53,361	6 %	62,947	(10 %)
All other	8,641	10,681	(19 %)	9,974	(13 %)
Total	332,236	287,410	16 %	324,001	3 %

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

	Three months ended March 31, 2019 Volume	Percent	2018 Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	17,453	58 %	14,745	57 %	2,708	18 %
Natural gas (MMcf)	74,690	42 %	66,730	43 %	7,960	12 %
Total (MBoe)	29,901	100 %	25,867	100 %	4,034	16 %

	Three months ended March 31, 2019 MBoe	Percent	2018 MBoe	Percent	Volume increase	Volume percent increase
North Region	18,711	63 %	15,400	60 %	3,311	22 %
South Region	11,190	37 %	10,467	40 %	723	7 %

Total	29,901	100 %	25,867	100 %	4,034	16 %

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The 18% increase in crude oil production for the 2019 first quarter was primarily driven by a 2,519 MBbls, or 22%, increase in Bakken production due to additional wells being completed. Additionally, crude oil production from the SCOOP play increased 545 MBbls, or 37%, from the prior year first quarter due to new well completions in our oil-weighted Project SpringBoard. These increases were partially offset by decreased crude oil production from various other areas due to natural declines in production.

The 12% increase in natural gas production for the 2019 first quarter was driven by a 5,445 MMcf, or 30%, increase in Bakken gas production in conjunction with the aforementioned increase in Bakken crude oil production over the prior year first quarter. Additionally, natural gas production in the STACK play increased 3,250 MMcf, or 14%, due to additional wells being completed. These increases were partially offset by reduced production from various other areas due to natural declines in production.

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. See the subsequent section titled Non-GAAP Financial Measures for a discussion and calculation of these measures.

Net crude oil and natural gas sales. Net crude oil and natural gas sales totaled $1.06 billion for the first quarter of 2019, consistent with net sales of $1.06 billion for the 2018 first quarter due to offsetting changes in sales volumes and net sales prices as discussed below.

Total sales volumes for the first quarter of 2019 increased 4,017 MBoe, or 16%, compared to the 2018 first quarter, reflecting an increase in drilling and completion activities over the past year. For the first quarter of 2019, our crude oil sales volumes increased 18% from the comparable 2018 period, while our natural gas sales volumes increased 12%.

Our crude oil net sales prices averaged $50.05 per barrel in the 2019 first quarter, a decrease of 15% compared to $58.98 per barrel for the 2018 first quarter primarily due to lower crude oil market prices. Crude oil market prices decreased significantly in late 2018 to 18-month lows and remained depressed in early 2019, causing our sales prices to be lower than prices realized in the 2018 first quarter. Crude oil prices have steadily improved from early 2019 levels.

The differential between NYMEX West Texas Intermediate calendar month prices and our realized crude oil net sales prices increased to $4.77 per barrel for the 2019 first quarter compared to $3.91 per barrel for the 2018 first quarter, reflecting changes in supply and demand fundamentals in the North region over the past year that created volatility in our Bakken price realizations between periods.

Our 2019 first quarter crude oil price differentials reflect a significant improvement from 2018 fourth quarter differentials, which averaged $8.44 per barrel, due to an increase in pipeline takeaway capacity, reduced Canadian crude oil imports, and reduced refinery maintenance downtime.

Our natural gas net sales prices averaged $2.56 per Mcf for the 2019 first quarter, a decrease of 14% compared to $2.98 per Mcf for the 2018 first quarter. The discount between our net sales prices and NYMEX Henry Hub calendar month prices weakened by $0.60 per Mcf compared to the 2018 first quarter. We sell the majority of our operated natural gas production to midstream customers at lease locations 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. NGL prices in 2019 have decreased from 2018 first quarter levels in conjunction with decreased crude oil prices and other factors, resulting in reduced price realizations for our natural gas sales stream relative to benchmark prices.

Derivatives. Changes in natural gas prices during the first quarter of 2019 had an unfavorable impact on the fair value of our natural gas derivatives, which resulted in negative revenue adjustments of $1.1 million in the current period compared to positive revenue adjustments of $10.2 million in the comparable 2018 period.

Operating Costs and Expenses

Production Expenses. Production expenses increased $14.0 million, or 15%, from $93.0 million for the first quarter of 2018 to $107.0 million for the first quarter of 2019 primarily due to an increase in the number of producing wells and related 16% increase in sales volumes. Production expenses on a per-Boe basis averaged $3.59 for the 2019 first quarter, slightly improved from $3.60 per Boe recognized for the 2018 first quarter.

Production Taxes. Production taxes increased $5.8 million, or 7%, to $86.4 million for the first quarter of 2019 compared to $80.6 million for the first quarter of 2018, despite lower revenues, primarily due to a significant increase in production and revenues generated in North Dakota from increased well completion activities over the past year. North Dakota has higher production tax rates compared to Oklahoma, which caused our production taxes as a percentage of net crude oil and natural gas sales to increase from 7.6% for the first quarter of 2018 to 8.2% for the first quarter of 2019. Additionally, in March 2018 new legislation was enacted 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 compared to the prior year first quarter.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $40.6 million, or 9%, to $495.0 million for the first quarter of 2019 compared to $454.4 million for the first quarter of 2018 due to an increase in total sales volumes, the impact of which was partially offset by a reduction in our DD&A rate per Boe as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Three months ended March 31,	
$/Boe	2019	2018
Crude oil and natural gas	$16.37	$17.35
Other equipment	0.16	0.20
Asset retirement obligation accretion	0.07	0.06
Depreciation, depletion, amortization and accretion	$16.60	$17.61

The reduction in our DD&A rate for crude oil and natural gas properties resulted from an increase in proved developed reserves over which costs are depleted due in part to higher average annual commodity prices in 2018 compared to 2017, along with improvements in drilling efficiencies and completion methods that have resulted in an increase in the quantity of proved reserves found and developed per dollar invested.

Property Impairments. There were no proved property impairments recognized in the first quarter periods of 2019 and 2018. Impairments of unproved properties decreased $8.5 million, or 25%, to $25.3 million for the 2019 first quarter compared to $33.8 million for the 2018 first quarter due to a reduction in the balance of unamortized leasehold costs over the past year.

General and Administrative Expenses. Total G&A expenses increased $4.6 million, or 11%, to $47.6 million for the first quarter of 2019 compared to $43.0 million for the first quarter of 2018. Total G&A expenses include non-cash charges for equity compensation of $12.1 million and $10.9 million for the first quarters of 2019 and 2018, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $35.5 million for the 2019 first quarter, an increase of $3.4 million, or 11%, compared to $32.1 million for the 2018 first quarter. We have incurred higher personnel-related costs in 2019 associated with the growth in our operations over the past year; however, the increased costs have been mitigated by higher overhead recoveries from joint interest owners driven by 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.

	Three months ended March 31,	
$/Boe	2019	2018
General and administrative expenses	$1.19	$1.25
Non-cash equity compensation	0.41	0.42
Total general and administrative expenses	$1.60	$1.67

Interest Expense. Interest expense decreased $8.1 million, or 11%, to $67.8 million for the first quarter of 2019 compared to $75.9 million for the first quarter of 2018 due to a decrease in total outstanding debt. Our weighted average outstanding debt balance was $5.8 billion for the 2019 first quarter compared to $6.4 billion for the 2018 first quarter.

Income Taxes. For the first quarters of 2019 and 2018 we provided for income taxes at a combined federal and state tax rate of 24.5% and 24.0%, respectively, of pre-tax income generated by our operations in the United States. We recorded income tax provisions of $52.0 million and $71.5 million for the first quarters of 2019 and 2018, respectively, which resulted in effective tax rates of 22% and 23%, respectively, after taking into account statutory tax rates, permanent taxable differences, tax effects from stock-based compensation, and other items. See Notes to Unaudited Condensed Consolidated Financial Statements–Note 12. Income Taxes for a summary of the sources and tax effects of items comprising our effective tax rates.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our 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 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 as of March 31, 2019, including those described in Note 9. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements, 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 provided by operating activities

Net cash provided by operating activities totaled $721.5 million and $886.2 million for the three months ended March 31, 2019 and 2018, respectively. The decrease in operating cash flows was primarily due to a decrease in crude oil and natural gas revenues driven by lower realized commodity prices in 2019 coupled with the aforementioned increases in production expenses, production taxes, and G&A expenses. The reduced cash flows from these factors were partially offset by higher cash gains on matured natural gas derivatives compared to the 2018 first quarter.

Cash flows used in investing activities

Net cash used in investing activities totaled $753.1 million and $628.2 million for the three months ended March 31, 2019 and 2018, respectively. The increase in spending resulted from changes in the timing of our allocation of annual capital spending between periods. Our 2019 capital expenditures reflect an increased pace of development due to improved drilling cycle times and efficiency gains which resulted in more net wells being drilled and completed and a greater portion of our spending being incurred in the first quarter in 2019 compared to 2018. Our capital expenditures budget for full year 2019 is $2.6 billion compared to $2.8 billion spent in 2018.

Cash flows from financing activities

Net cash provided by financing activities for the three months ended March 31, 2019 totaled $13.2 million, which includes $38.2 million of contributions received from Franco-Nevada Corporation for the funding of its share of mineral acquisition costs incurred by The Mineral Resources Company II, LLC as described below under the heading "Mineral acquisition relationship." Partially offsetting these cash inflows was $20.6 million of cash paid to taxing authorities to satisfy tax withholdings associated with restricted stock awards that vested during the period.

Net cash used in financing activities for the three months ended March 31, 2018 totaled $203.7 million, primarily resulting from $188 million of net repayments on our credit facility using available cash flows from operations.

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 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 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 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.

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 April 29, 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 Notes to Unaudited Condensed 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 March 31, 2019 and expect to maintain compliance for at least the next 12 months. At March 31, 2019, our consolidated net debt to total capitalization ratio was 0.42 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.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $5.8 billion at March 31, 2019. 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 Note 7. Long-Term Debt in Notes to Unaudited Condensed Consolidated Financial Statements.

In 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 and amount of which is uncertain.

We were in compliance with our senior note covenants at March 31, 2019 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.

Mineral acquisition relationship

In October 2018, Continental entered into a strategic relationship with Franco-Nevada Corporation to acquire oil and gas mineral interests within an area of mutual interest in the SCOOP and STACK plays through a minerals subsidiary named The Mineral Resources Company II, LLC ("TMRC II"). Under the relationship, the parties have committed, subject to satisfaction of agreed upon acreage development thresholds, to spend a remaining aggregate total of approximately $257 million through year-end 2021 to acquire mineral interests. 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 predetermined production targets, while Franco-Nevada will fund 80% of future acquisitions and will be entitled to receive between 50% and 75% of TMRC II's revenues. Based upon production targets achieved to date, Continental is currently earning 50% of TMRC II's revenues and such allocation will continue for the remainder of 2019.

Capital expenditures

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.

For the three months ended March 31, 2019, we invested $750.2 million in our capital program excluding $15.8 million of unbudgeted acquisitions and including $12.1 million of capital costs associated with increased accruals for capital expenditures. Our 2019 year to date capital expenditures were allocated as shown in the table below. Our first quarter capital expenditures reflect an accelerated pace of development due to improved cycle times and efficiency gains which resulted in more net wells being spud and completed during the quarter than budgeted while using the same number of rigs and completion crews.

In millions	1Q 2019
Exploration and development drilling	$ 631.1
Land costs (1)	66.1
Capital facilities, workovers and other corporate assets	52.6
Seismic	0.4
Capital expenditures, excluding unbudgeted acquisitions	750.2
Acquisitions of producing properties	15.8
Acquisitions of non-producing properties	—
Total unbudgeted acquisitions	15.8
Total capital expenditures	$ 766.0

(1) Amount includes $51 million of mineral acquisitions made by TMRC II during the first quarter, of which $42 million was recouped 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.

Commitments and contingencies

Refer to Note 9. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements for discussion of certain future commitments and contingencies of the Company as of March 31, 2019. We believe our cash flows from operations, our remaining cash balance, and amounts available under our credit facility will be sufficient to satisfy such commitments and contingencies.

Off-balance sheet arrangements

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

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our 2018 Form 10-K.

New Accounting Pronouncements

See Note 2. Basis of Presentation and Significant Accounting Policies in Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of the new lease accounting standard adopted on January 1, 2019 along with a discussion of an accounting pronouncement not yet adopted.

Non-GAAP Financial Measures

Net crude oil and natural gas sales and net sales prices

Revenues and transportation expenses associated with production from our operated properties are reported separately as discussed in Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues. 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. As a result, the separate presentation of revenues and transportation expenses from our operated properties differs from the net presentation 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 and to achieve comparability between operated and non-operated revenues, 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 crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the three months ended March 31, 2019 and 2018.

	Three months ended March 31, 2019			Three months ended March 31, 2018		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$911,118	$198,466	$1,109,584	$906,281	$207,571	$1,113,852
Less: Transportation expenses	(41,648)	(7,491)	(49,139)	(40,386)	(8,911)	(49,297)
Net crude oil and natural gas sales (non-GAAP)	$869,470	$190,975	$1,060,445	$865,895	$198,660	$1,064,555
Sales volumes (MBbl/MMcf/MBoe)	17,373	74,690	29,821	14,682	66,730	25,804
Net sales price (non-GAAP)	$50.05	$2.56	$35.56	$58.98	$2.98	$41.26

ITEM 3. 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 three months ended March 31, 2019, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $708 million for each $10.00 per barrel change in crude oil prices at March 31, 2019 and $303 million for each $1.00 per Mcf change in natural gas prices at March 31, 2019.

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 natural gas production through December 2019. Our future crude oil production is currently unhedged and directly exposed to volatility in market prices, whether favorable or unfavorable.

Changes in natural gas prices during the three months ended March 31, 2019 had an overall unfavorable impact on the fair value of our derivative instruments. For the three months ended March 31, 2019, we recognized non-cash mark-to-market losses on natural gas derivatives of $14.2 million which were partially offset by cash gains on natural gas derivatives of $13.1 million.

The fair value of our natural gas derivative instruments at March 31, 2019 was a net asset of $1.4 million. An assumed increase in the forward prices used in the March 31, 2019 valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $139 million at March 31, 2019. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $141 million at March 31, 2019. 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 ($699 million in receivables at March 31, 2019); our joint interest and other receivables ($396 million at March 31, 2019); and counterparty credit risk associated with our derivative instrument receivables, if any.

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 $92 million at March 31, 2019, 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 variable-rate borrowings, if any, we may have outstanding from time to time under our 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. 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 had no outstanding borrowings on our credit facility at April 29, 2019.

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.

ITEM 4. 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 March 31, 2019 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

During the three months ended March 31, 2019, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. 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 risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even an effective system of internal control will provide only reasonable assurance that the objectives of the internal control system are met.

PART II. Other Information

ITEM 1. Legal Proceedings
See Note 9. Commitments and Contingencies–Litigation in Part I, Item I. Financial Statements–Notes to Unaudited Condensed 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 1A. Risk Factors
In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our 2018 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q, if any, and in our 2018 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.
There have been no material changes in our risk factors from those disclosed in our 2018 Form 10-K.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Recent Sales of Unregistered Securities – Not applicable.
(b) Use of Proceeds – Not applicable.
(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers – The following table provides information about purchases of shares of our common stock during the three months ended March 31, 2019:

Period	Total number of shares purchased (1)		Average price paid per share		Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
January 1, 2019 to January 31, 2019	—		—		—	—
February 1, 2019 to February 28, 2019	1,323,396	(2)	$ 45.30	(2)	—	—
March 1, 2019 to March 31, 2019	791,828	(3)	42.95	(3)	—	—
Total	2,115,224		$ 44.42		—	—

(1) In connection with restricted stock grants under the Company's 2013 Long-Term Incentive 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 unless otherwise noted. We paid the associated taxes to the applicable taxing authorities.

(2) Of this amount, 439,419 shares represent shares surrendered by employees to cover tax liabilities at an average price per share of $46.93. The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares. Additionally, the amount includes 883,977 shares of our common stock purchased by Harold G. Hamm, our Chairman of the Board, Chief Executive Officer, and principal shareholder in open-market transactions at an average price per share of $44.49.

(3) Represents shares of our common stock purchased by Harold G. Hamm in open-market transactions.

ITEM 3. Defaults Upon Senior Securities
Not applicable.

ITEM 4. Mine Safety Disclosures
Not applicable.

ITEM 5. Other Information
Not applicable.

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ITEM 6. Exhibits

The exhibits required to be filed 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 quarterly period 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.
10.1*†	Amended and Restated Continental Resources, Inc. 2013 Long-Term Incentive Plan.
10.2*†	Amended and restated form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan.
10.3*†	Amended and restated form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan.
10.4*†	Description of cash bonus plan updated as of February 12, 2019.
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).
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.

SIGNATURE

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

CONTINENTAL RESOURCES, INC.

Date:	April 29, 2019	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer
			(Duly Authorized Officer and Principal Financial Officer)