CONTINENTAL RESOURCES, INC
Form 10-Q
May 02, 2018
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, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-32886

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

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

(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)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 ¨ (Do not check if a smaller reporting company)	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
376,031,587 shares of our $0.01 par value common stock were outstanding on April 30, 2018.

Table of Contents

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 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.
“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,” “plan,” “continue,” “potential,” “guidance,” 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, 2017, 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, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$98,145	$43,902
Receivables:		
Crude oil and natural gas sales	642,534	671,665
Affiliated parties	73	63
Joint interest and other, net	417,429	426,585
Derivative assets	8,683	2,603
Inventories	107,169	97,406
Prepaid expenses and other	17,022	9,501
Total current assets	1,291,055	1,251,725
Net property and equipment, based on successful efforts method of accounting	13,073,054	12,933,789
Other noncurrent assets	13,408	14,137
Total assets	$14,377,517	$14,199,651
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$739,932	$692,908
Revenues and royalties payable	393,372	374,831
Payables to affiliated parties	155	143
Accrued liabilities and other	255,412	260,074
Derivative liabilities	102	—
Current portion of long-term debt	2,304	2,286
Total current liabilities	1,391,277	1,330,242
Long-term debt, net of current portion	6,163,775	6,351,405
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,331,094	1,259,558
Asset retirement obligations, net of current portion	114,840	111,794
Other noncurrent liabilities	15,310	15,449
Total other noncurrent liabilities	1,461,244	1,386,801
Commitments and contingencies (Note 8)		
Shareholders’ 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; 376,057,204 shares issued and outstanding at March 31, 2018; 375,219,769 shares issued and outstanding at December 31, 2017	3,760	3,752
Additional paid-in capital	1,405,388	1,409,326
Accumulated other comprehensive income	309	307
Retained earnings	3,951,764	3,717,818
Total shareholders’ equity	5,361,221	5,131,203
Total liabilities and shareholders’ equity	$14,377,517	$14,199,651

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	2018	2017
Revenues:		
Crude oil and natural gas sales	$1,113,852	$633,850
Gain on natural gas derivatives, net	10,174	46,858
Crude oil and natural gas service operations	17,002	4,719
Total revenues	1,141,028	685,427
Operating costs and expenses:		
Production expenses	92,962	72,854
Production taxes	80,580	41,234
Transportation expenses	49,297	—
Exploration expenses	1,720	4,998
Crude oil and natural gas service operations	4,583	2,837
Depreciation, depletion, amortization and accretion	454,378	382,156
Property impairments	33,784	51,372
General and administrative expenses	43,043	47,220
Net (gain) loss on sale of assets and other	(41)	5,535
Total operating costs and expenses	760,306	608,206
Income from operations	380,722	77,221
Other income (expense):		
Interest expense	(75,894)	(71,172)
Other	654	442
	(75,240)	(70,730)
Income before income taxes	305,482	6,491
Provision for income taxes	(71,536)	(6,022)
Net income	$233,946	$469
Basic net income per share	$0.63	$—
Diluted net income per share	$0.63	$—
Comprehensive income:		
Net income	$233,946	$469
Other comprehensive income, net of tax:		
Foreign currency translation adjustments	2	138
Total other comprehensive income, net of tax	2	138
Comprehensive income	$233,948	$607

The accompanying notes are an integral part of these condensed consolidated financial statements.
2

Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statement of Shareholders' Equity

In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive income	Retained earnings	Total shareholders' equity
Balance at December 31, 2017	375,219,769	$3,752	$1,409,326	$ 307	$3,717,818	$5,131,203
Net income (unaudited)	—	—	—	—	233,946	233,946
Other comprehensive income, net of tax (unaudited)	—	—	—	2	—	2
Stock-based compensation (unaudited)	—	—	10,905	—	—	10,905
Restricted stock:						
Granted (unaudited)	1,180,032	12	—	—	—	12
Repurchased and canceled (unaudited)	(276,108)	(3)	(14,843)	—	—	(14,846)
Forfeited (unaudited)	(66,489)	(1)	—	—	—	(1)
Balance at March 31, 2018 (unaudited)	376,057,204	$3,760	$1,405,388	$ 309	$3,951,764	$5,361,221

The accompanying notes are an integral part of these condensed consolidated financial statements.
3

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

In thousands	Three months ended March 31, 2018			2017		
Cash flows from operating activities						
Net income	$	233,946		$	469	
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation, depletion, amortization and accretion	455,559			381,385		
Property impairments	33,784			51,372		
Non-cash gain on derivatives, net	(5,978		)	(45,155		)
Stock-based compensation	10,916			11,438		
Provision for deferred income taxes	71,536			6,021		
Dry hole costs	1			157		
(Gain) loss on sale of assets, net	(41		)	3,638		
Other, net	3,397			3,099		
Changes in assets and liabilities:						
Accounts receivable	38,268			(22,053		)
Inventories	(9,763		)	13,297		
Other current assets	(6,343		)	(3,111		)
Accounts payable trade	48,307			61,745		
Revenues and royalties payable	18,541			20,543		
Accrued liabilities and other	(5,848		)	(12,338		)
Other noncurrent assets and liabilities	(91		)	(306		)
Net cash provided by operating activities	886,191			470,201		
Cash flows from investing activities						
Exploration and development	(618,200		)	(388,596		)
Purchase of producing crude oil	(2,647		)	(137		)

and natural gas properties		
Purchase of other property and equipment	(7,421)	(6,336)
Proceeds from sale of assets	57	5,798
Net cash used in investing activities	(628,211)	(389,271)
Cash flows from financing activities		
Credit facility borrowings	370,000	256,000
Repayment of credit facility	(558,000)	(326,000)
Repayment of other debt	(566)	(548)
Debt issuance costs	(312)	—
Repurchase of restricted stock for tax withholdings	(14,846)	(9,837)
Net cash used in financing activities	(203,724)	(80,385)
Effect of exchange rate changes on cash	(13)	—
Net change in cash and cash equivalents	54,243	545
Cash and cash equivalents at beginning of period	43,902	16,643
Cash and cash equivalents at end of period	$ 98,145	$ 17,188

The accompanying notes are an integral part of these condensed consolidated financial statements.
4

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 originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company's principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP and STACK areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.
A substantial portion of the Company’s operations are located in the North region, with that region comprising 60% of the Company’s crude oil and natural gas production and 73% of its crude oil and natural gas revenues for the three months ended March 31, 2018. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. In recent years, the Company has significantly expanded its operations in the South region with its increased activity in the SCOOP and STACK plays. The South region comprised 40% of the Company's crude oil and natural gas production and 27% of its crude oil and natural gas revenues for the three months ended March 31, 2018.
For the three months ended March 31, 2018, crude oil accounted for 57% of the Company’s total production and 81% 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 and its subsidiaries, all of which are 100% owned, after all significant intercompany accounts and transactions have been eliminated upon consolidation.
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, 2017 (“2017 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, 2018 and for the three month periods ended March 31, 2018 and 2017 are unaudited. The condensed consolidated balance sheet as of December 31, 2017 was derived from the audited balance sheet included in the 2017 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 interim 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 by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects the potential dilution

of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income per share for the three months ended

5

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

March 31, 2018 and 2017.

	Three months ended March 31,	
In thousands, except per share data	2018	2017
Net income (numerator)	$233,946	$ 469
Weighted average shares (denominator):		
Weighted average shares - basic	371,543	370,831
Non-vested restricted stock	2,638	2,522
Weighted average shares - diluted	374,181	373,353
Net income per share:		
Basic	$0.63	$ —
Diluted	$0.63	$ —

Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines 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 market 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, 2018 and December 31, 2017 consisted of the following:

In thousands	March 31, 2018	December 31, 2017
Tubular goods and equipment	$16,150	$ 14,946
Crude oil	91,019	82,460
Total	$107,169	$ 97,406

Adoption of new accounting pronouncements

Revenue recognition and presentation – In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes nearly all previously existing revenue recognition guidance under U.S. GAAP. Subsequently, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This new guidance became effective for reporting periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on January 1, 2018 as required. See Note 4. Revenues for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New accounting pronouncements not yet adopted

Leases – In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for interim and annual reporting periods beginning after December 15, 2018 and, under current guidance, requires adoption by application of a modified retrospective transition approach whereby an entity shall initially apply the new requirements as of the beginning of the earliest period presented in the financial statements. In 2018, the FASB proposed preliminary guidance that is expected to ease the transition requirements by providing an adoption alternative that allows entities to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption in lieu of retrospectively applying the guidance to pre-adoption periods. Such guidance is not yet final and may not be adopted by the FASB as proposed or at all.

The Company continues to evaluate the impact of ASU 2016-02 on its financial statements, accounting policies and internal controls and is in the process of implementing systems and processes to identify, classify, and account for leases within the scope of the new guidance and to comply with the related disclosure requirements. Standard setting guidance and interpretations continue to evolve and are being monitored for applicability and impact to the Company's business and industry. Based on an initial review of the new guidance and the Company’s current commitments, the

Company anticipates it will be required to recognize lease assets and liabilities related to drilling rig commitments, certain equipment rentals and leases, certain surface use agreements, and potentially certain firm transportation agreements, as well as other arrangements, the effect

6

of which cannot be estimated at this time due to changes and uncertainties in the nature, timing, and extent of the Company's contractual arrangements from period to period.

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

Note 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.

	Three months ended March 31,	
In thousands	2018	2017
Supplemental cash flow information:		
Cash paid for interest	$52,251	$57,952
Cash paid for income taxes	—	2
Cash received for income tax refunds	5	148
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	1,609	1,565

As of March 31, 2018 and December 31, 2017, the Company had $301.5 million and $302.8 million, respectively, of accrued capital expenditures included in “Net property and equipment” and “Accounts payable trade” in the condensed consolidated balance sheets.

Note 4. Revenues

Adoption of new revenue recognition and disclosure guidance

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

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

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

The new guidance does not have a material impact on the timing of the Company’s revenue recognition or its financial position, results of operations, net income, or cash flows, but does impact the Company's presentation of revenues and expenses under the gross-versus-net presentation guidance in ASU 2016-08. In years prior to 2018, the Company generally presented its revenues net of costs incurred to transport its production to market. Under the new guidance, revenues and transportation expenses associated with the majority of production originating from the Company’s operated properties are now reported on a

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

gross basis as further discussed below. The changes from net to gross presentation resulted in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company's results of operations, net income, or cash flows for the three months ended March 31, 2018.

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

	Three months ended March 31, 2018		
In thousands	New Standard	Prior Presentation	Change
Revenues:			
Crude oil and natural gas sales	$1,113,852	$ 1,064,555	$49,297
Gain on natural gas derivatives, net	10,174	10,174	—
Crude oil and natural gas service operations	17,002	17,002	—
Total revenues	$1,141,028	$ 1,091,731	$49,297
Operating costs and expenses:			
Transportation expenses	$49,297	$ —	$49,297
Net income	$233,946	$ 233,946	$—

Revenue from contracts with customers

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

Operated crude oil revenues – The Company pays third parties to transport the majority of its operated crude oil production from lease locations to downstream market centers, at which time the Company's customers take title and custody of the product in exchange for prices based on the particular market where the product was delivered. Operated crude oil revenues are recognized during the month in which title transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. Crude oil sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred. Operated crude oil revenues and transportation expenses are reported on a gross basis, as the Company controls the operated production prior to its transfer to customers. Transportation expenses associated with the Company's operated crude oil production totaled $40.4 million for the three months ended March 31, 2018.

Operated natural gas revenues – The Company sells the majority of its operated natural gas production to midstream customers at its lease locations under multi-year term contracts based on market prices in the field where the sales occur. Under these arrangements, the midstream customers take title to the full gas stream at the lease location, and the Company's gross 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 customer's proceeds from the sale of residue gas and natural gas liquids ("NGLs") at secondary downstream markets, and contractual pricing adjustments reflecting the customer's estimated recoupment of its investment over time. Such revenues are recognized during the month in which title transfers to the customer at the lease location 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 may elect 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 based on the customer's proceeds for sale of those processed products. When the Company elects to do so, it pays third parties to transport the processed products which it took in-kind to downstream delivery points, where it then sells the products to customers at prices applicable to those downstream markets. In such situations, operated revenues are recognized during the month in which title 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 $8.9 million for the three months ended March 31, 2018, comprised entirely of costs to transport processed residue gas.

Non-operated crude oil and natural gas revenues – The Company's proportionate share of production from non-operated properties is 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,

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

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.

Natural gas derivative revenues – 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. Such activities occur on a daily basis in association with the Company's operation of jointly-owned properties. 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, 2018.

	Three months ended March 31, 2018		
In thousands	North Region	South Region	Total
Crude oil revenues:			
Operated properties	$569,211	$138,453	$707,664
Non-operated properties	182,887	15,730	198,617
Total crude oil revenues	752,098	154,183	906,281
Natural gas revenues:			
Operated properties	51,820	127,254	179,074
Non-operated properties	13,680	14,817	28,497
Total natural gas revenues	65,500	142,071	207,571
Crude oil and natural gas sales	$817,598	$296,254	$1,113,852
Timing of revenue recognition			
Goods transferred at a point in time	$817,598	$296,254	$1,113,852
Goods transferred over time	—	—	—
	$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 title to customers. Upon delivery of production, the Company has a right to receive consideration from its customers in amounts that correspond with the value of the production transferred.

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

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

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

Contract balances

Under the Company's crude oil and natural gas sales contracts or arrangements 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 arrangements 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 our financial statements within the caption "Crude oil and natural gas sales". Revenues recognized during the three months ended March 31, 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. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.

The Company recognizes its natural gas derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its natural gas 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 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.

At March 31, 2018 the Company had outstanding natural gas derivative contracts as set forth in the table below. The volumes reflected below represent an aggregation of multiple derivative contracts having similar remaining durations expected to be realized ratably over the remainder of 2018. At March 31, 2018 the Company had no outstanding crude oil derivative contracts.

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
April 2018 - December 2018		

Swaps - Henry Hub	173,250,000	$ 2.88

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

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 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.

In thousands	Three months ended March 31, 2018	2017
Cash received (paid) on derivatives:		
Natural gas fixed price swaps	$4,196	$5,478
Natural gas collars	—	(6,406)
Cash received (paid) on derivatives, net	4,196	(928)
Non-cash gain on derivatives:		
Natural gas fixed price swaps	5,978	22,896
Natural gas collars	—	24,890
Non-cash gain on derivatives, net	5,978	47,786
Gain on natural gas derivatives, net	$10,174	$46,858

Diesel fuel derivatives

The Company previously entered into diesel fuel swap derivative contracts, all of which matured on or before December 31, 2017, to economically hedge against the variability in cash flows associated with purchases of diesel fuel for use in drilling activities. With respect to the diesel fuel swap contracts, the counterparty was required to make a payment to the Company if the settlement price for any settlement period was greater than the swap price, and the Company was required to make a payment to the counterparty if the settlement price for any settlement period was less than the swap price. The diesel fuel swap contracts were settled based upon reported NYMEX settlement prices for New York Harbor ultra-low sulfur diesel fuel.

The Company recognized its diesel fuel derivatives on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value was based upon various factors, including commodity exchange prices, over-the-counter quotations, the risk-free interest rate, and time to expiration. The Company did not designate its diesel fuel derivatives as hedges for accounting purposes and, as a result, marked the derivative instruments to fair value and recognized the changes in fair value in the unaudited condensed consolidated statements of comprehensive income under the caption “Operating costs and expenses—Net (gain) loss on sale of assets and other.”

Cash receipts in the following table reflect gains on diesel fuel derivatives which matured during the 2017 period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash losses below represent the change in fair value of diesel fuel derivatives held at March 31, 2017 and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the first quarter of 2017.

In thousands	Three months ended March 31, 2018	2017
Cash received on diesel fuel derivatives	$—	$734
Non-cash loss on diesel fuel derivatives	—	(2,631)
Loss on diesel fuel derivatives, net	$—	$(1,897)

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.

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

The following table presents the gross amounts of recognized natural gas and diesel fuel 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, 2018	December 31, 2017
Commodity derivative assets:		
Gross amounts of recognized assets	$14,405	$ 2,603
Gross amounts offset on balance sheet	(5,722)	—
Net amounts of assets on balance sheet	8,683	2,603
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(5,824)	—
Gross amounts offset on balance sheet	5,722	—
Net amounts of liabilities on balance sheet	$(102)	$ —

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, 2018	December 31, 2017
Derivative assets	$ 8,683	$ 2,603
Noncurrent derivative assets	—	—
Net amounts of assets on balance sheet	8,683	2,603
Derivative liabilities	(102)	—
Noncurrent derivative liabilities	—	—
Net amounts of liabilities on balance sheet	(102)	—
Total derivative assets, net	$ 8,581	$ 2,603

Note 6. Fair Value Measurements

The Company follows a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

	Fair value measurements at March 31, 2018 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets:				
Swaps	$ —	$ 8,581	$ —	$8,581
Total	$ —	$ 8,581	$ —	$8,581

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

Assets Measured at Fair Value on a Nonrecurring Basis

Certain assets are reported at fair value on a nonrecurring basis in the 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 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 2022 (adjusted for differentials), escalating 3% per year thereafter
Operating costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 1 to 38 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.

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

For the three months ended March 31, 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 that period.

For the three months ended March 31, 2017, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Impairments of proved properties totaled $0.9 million for the three months ended March 31, 2017, primarily for properties in a non-core area of the North region. The impaired properties were written down to their estimated fair value at the time of impairment of approximately $3.4 million.

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

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

	Three months ended March 31,	
In thousands	2018	2017
Proved property impairments	$—	$871
Unproved property impairments	33,784	50,501
Total	$33,784	$51,372

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, 2018		December 31, 2017	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Debt:				
Revolving credit facility	$—	$—	$188,000	$188,000
Note payable	9,411	9,300	9,974	9,900
5% Senior Notes due 2022	1,997,678	2,032,500	1,997,576	2,040,000
4.5% Senior Notes due 2023	1,487,240	1,517,800	1,486,690	1,526,800
3.8% Senior Notes due 2024	992,311	964,200	992,036	988,800
4.375% Senior Notes due 2028	988,045	976,200	988,061	987,200
4.9% Senior Notes due 2044	691,394	668,900	691,354	679,900
Total debt	$6,166,079	$6,168,900	$6,353,691	$6,420,600

The fair value of revolving credit facility borrowings at December 31, 2017 approximate carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and are classified as Level 2 in the fair value hierarchy.

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

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

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

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

Note 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $43.4 million and $44.3 million at March 31, 2018 and December 31, 2017, respectively, consists of the following.

In thousands	March 31, 2018	December 31, 2017
Revolving credit facility	$—	$ 188,000
Note payable	9,411	9,974
5% Senior Notes due 2022	1,997,678	1,997,576
4.5% Senior Notes due 2023	1,487,240	1,486,690
3.8% Senior Notes due 2024	992,311	992,036
4.375% Senior Notes due 2028	988,045	988,061
4.9% Senior Notes due 2044	691,394	691,354
Total debt	$6,166,079	$ 6,353,691
Less: Current portion of long-term debt	2,304	2,286
Long-term debt, net of current portion	$6,163,775	$ 6,351,405

Revolving Credit Facility

At March 31, 2018, the Company had an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.75 billion. The Company had no outstanding borrowings on its credit facility at March 31, 2018.

On April 9, 2018, the Company entered into a new unsecured revolving credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. In connection with the execution of the new credit facility, the Company terminated its then-existing credit facility that was due to mature in May 2019.

Borrowings under the new 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 had no outstanding borrowings on its new credit facility at April 30, 2018. The Company incurs commitment fees based on currently assigned credit ratings of 0.20% per annum on the daily average amount of unused borrowing availability under its new credit facility.

The Company's new credit facility retains substantially the same restrictive covenants as the previous credit facility, 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, 2018.

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

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, 2018.

	2022 Notes (1)	2023 Notes	2024 Notes	2028 Notes	2044 Notes
Face value (in thousands)	$2,000,000	$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 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 prices or 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 price 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, 2018. Three of the Company's subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company's other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Note Payable

In February 2012, 20 Broadway Associates LLC, a 100% 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 $2.3 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, 2018.

Note 8. Commitments and Contingencies

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

Drilling commitments – As of March 31, 2018, the Company has drilling rig contracts with various terms extending to February 2020 to ensure rig availability in its key operating areas. Future commitments as of March 31, 2018 total approximately $81 million, of which $49 million is expected to be incurred in the remainder of 2018, $31 million in 2019, and $1 million in 2020.

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, 2018 under the arrangements amount to approximately $1.3 billion, of which $151 million is expected to be incurred in the remainder of 2018, $212 million in 2019, $182 million in 2020, $163 million in 2021, $162 million in 2022, and $474 million thereafter. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition, as amended, alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and sought recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. The Company denied all allegations and denied that the case was properly brought as a class action. On June 11, 2015, the trial court certified a “hybrid” class requested by plaintiffs over the objections of the Company. The Company appealed the trial court’s class certification order. On February 8, 2017, the Oklahoma Court of Civil Appeals reversed the trial court’s ruling on certification and remanded the case for further proceedings. The plaintiffs filed a Petition for Rehearing which was denied by the Oklahoma Court of Civil Appeals. Plaintiffs then filed a Petition for Writ of Certiorari on May 23, 2017 to the Oklahoma Supreme Court, which was denied on October 2, 2017. On October 10, 2017, Plaintiffs filed with the trial court a “Second Amended and Renewed Motion for Class Action Certification and Request that the Court to Set a Briefing Schedule Related to Class Certification.” During the litigation the Company was not able to estimate a reasonably possible loss or range of loss or what impact, if any, the ultimate resolution of the action would have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the existence and the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. The Company further disclosed that it was reasonably possible one or more events could occur in the near term that could impact the Company’s ability to estimate the potential effect of this matter if any, on its financial condition, results of operations or cash flows. During the litigation the Company also disclosed plaintiffs alleged underpayments in excess of $200 million as damages, which may increase with the passage of time, a majority of which would be comprised of interest. After certification of the case as a class action was reversed the parties continued settlement negotiations. Due to the uncertainty of and burdens of litigation, on February 16, 2018, the Company reached a settlement in connection with this matter. Under the settlement, the Company initially expected to make payments and incur costs associated with the settlement of approximately $59.6 million, which is subject to change pending final approval of the settlement by the court. The Company accrued a loss for such amount at December 31, 2017, which was subsequently increased to $60.6 million at March 31, 2018 to reflect additional settlement obligations resulting from the passage of time. Such accrual is included in “Accrued liabilities and other” on the condensed consolidated balance sheets. On April 3, 2018, the District Court of Garfield County, Oklahoma preliminarily approved the settlement and set certain dates applicable to the settlement including the timing and content of Notice, Opt-out, and Objections to Class Members. The Fairness Hearing is currently scheduled for June 1, 2018.

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, 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, 2018 and December 31, 2017 the Company recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $7.9 million and $7.6 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 9. 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 $10.9 million and $11.4 million for the three months ended March 31, 2018 and 2017, 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, 2018, the Company had 13,701,105 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.

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

A summary of changes in non-vested restricted shares outstanding for the three months ended March 31, 2018 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2017	4,026,110	$ 35.63
Granted	1,180,032	51.42
Vested	(975,625)	47.32
Forfeited	(66,489)	34.53
Non-vested restricted shares outstanding at March 31, 2018	4,164,028	$ 37.38

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, 2018 was approximately $52.5 million. As of March 31, 2018, there was approximately $104 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.7 years.

Note 10. Accumulated Other Comprehensive Income (Loss)

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive income" within shareholders' equity in 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 (loss) for the three months ended March 31, 2018 and 2017:

	Three months ended March 31,	
In thousands	2018	2017
Beginning accumulated other comprehensive income (loss), net of tax	$307	$(260)
Foreign currency translation adjustments	2	138
Income taxes (1)	—	—
Other comprehensive income, net of tax	2	138
Ending accumulated other comprehensive income (loss), net of tax	$309	$(122)

(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 11. 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.

The Company's provision for income taxes totaled $71.5 million and $6.0 million for the three months ended March 31, 2018 and 2017, 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

18

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

in the table below:

	Three months ended March 31,			
$ in thousands	2018	Tax rate %	2017	Tax rate %
Expected income tax provision based on US statutory tax rate (1)	$(64,151)	21.0%	$(2,272)	35.0%
State income taxes, net of federal benefit	(9,164)	3.0 %	(195)	3.0 %
Tax benefit (deficiency) from stock-based compensation	1,509	(0.5 %)	(3,300)	50.8%
Canadian valuation allowance (2)	(69)	— %	(145)	2.2 %
Other, net	339	(0.1 %)	(110)	1.7 %
Provision for income taxes	$(71,536)	23.4%	$(6,022)	92.7%

(1) In December 2017 the Tax Cuts and Jobs Act was signed into law, which among other things reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

(2) Represents valuation allowances recognized against all deferred tax assets associated with operating loss carryforwards generated by the Company's Canadian operations during the respective periods for which the Company does not expect to realize a benefit.

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 Annual Report on Form 10-K for the year ended December 31, 2017. 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 Annual Report on Form 10-K for the year ended December 31, 2017, 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. 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.

Change in presentation of revenues

As discussed in Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues, we adopted new revenue recognition and presentation rules on January 1, 2018. The new rules did not have a material impact on the timing of our revenue recognition or our financial position, results of operations, net income, or cash flows for the first quarter of 2018, but did impact the presentation of our crude oil and natural gas revenues. We adopted the new rules using a modified retrospective transition approach whereby changes have been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation.

Under the new rules, revenues and transportation expenses associated with the majority of production from our operated properties are now reported on a gross basis compared to net presentation in the prior year. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice. As a result, beginning January 1, 2018 the gross presentation of revenues from the majority of our operated properties differs from the net presentation of revenues from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results, and to achieve comparability with prior period metrics for analysis purposes, we have presented crude oil and natural gas sales net of transportation expenses within MD&A, 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, 2018. Information is also presented for the three months ended March 31, 2017 for comparative purposes.

	Three months ended March 31, 2018			Three months ended March 31, 2017		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$906,281	$207,571	$1,113,852	$480,641	$153,209	$633,850
Less: Transportation expenses	(40,386)	(8,911)	(49,297)	—	—	—

Net crude oil and natural gas sales (non-GAAP for 2018)	$865,895	$198,660	$1,064,555	$480,641	$153,209	$633,850
Sales volumes (MBbl/MMcf/MBoe)	14,682	66,730	25,804	10,754	51,059	19,264
Net sales price (non-GAAP for 2018)	$58.98	$2.98	$41.26	$44.69	$3.00	$32.90

First Quarter 2018 Highlights

Production

Total production for the first quarter of 2018 averaged 287,410 Boe per day, consistent with the fourth quarter of 2017 and 34% higher than the first quarter of 2017.

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

Boe production per day	1Q 2018	1Q 2017	% Change from 1Q 2017	4Q 2017	% Change from 4Q 2017
Bakken	161,356	108,992	48 %	165,598	(3 %)
SCOOP	62,012	62,178	— %	62,242	— %
STACK	53,361	29,216	83 %	47,914	11 %
All other	10,681	13,369	(20 %)	11,231	(5 %)
Total	287,410	213,755	34 %	286,985	— %

Revenues

Net crude oil and natural gas sales totaled $1.1 billion for the 2018 first quarter, a 68% increase compared to the 2017 first quarter driven by a 32% increase in crude oil net sales prices coupled with a 34% increase in total sales volumes.

Cash flows

Net cash inflows from operating activities totaled $886.2 million for the first quarter of 2018, exceeding net cash outflows from investing activities by $258.0 million, the excess of which was primarily applied toward reducing debt and increasing our cash on hand.

Debt and liquidity

Total debt decreased $188 million, or 3%, in the first quarter of 2018.

At March 31, 2018, we had no outstanding borrowings on our credit facility and $98.1 million of cash and cash equivalents.

On April 9, 2018 we entered into a new unsecured credit facility, maturing in April 2023, with aggregate lender commitments totaling $1.5 billion. The new credit facility replaced our previous $2.75 billion credit facility that was due to mature in May 2019.

At April 30, 2018, we continued to have no outstanding credit facility borrowings.

Capital expenditures and drilling activity

Non-acquisition capital expenditures totaled $596.3 million for the first quarter of 2018 compared to $495.7 million for the 2017 fourth quarter and $427.0 million for the first quarter of 2017.

For the 2018 first quarter we participated in the drilling and completion of 135 gross (49 net) wells compared to 167 gross (50 net) wells in the 2017 fourth quarter and 94 gross (31 net) wells in the 2017 first quarter.

Financial and operating highlights

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

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

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

	Three months ended March 31,	
	2018	2017
Average daily production:		
Crude oil (Bbl per day)	163,837	119,201
Natural gas (Mcf per day)	741,442	567,328
Crude oil equivalents (Boe per day)	287,410	213,755
Average net sales prices (1):		
Crude oil ($/Bbl)	$58.98	$44.69
Natural gas ($/Mcf)	$2.98	$3.00
Crude oil equivalents ($/Boe)	$41.26	$32.90
Crude oil net sales price discount to NYMEX ($/Bbl)	$(3.91)	$(7.09)
Natural gas net sales price discount to NYMEX ($/Mcf)	$—	$(0.29)
Production expenses ($/Boe)	$3.60	$3.78
Production taxes (% of net crude oil and natural gas sales)	7.6 %	6.5 %
Depreciation, depletion, amortization and accretion ($/Boe)	$17.61	$19.84
Total general and administrative expenses ($/Boe)	$1.67	$2.45

(1) See the previous section titled Change in presentation of revenues for a discussion and calculation of net sales prices, which are non-GAAP measures for the three months ended March 31, 2018.

Three months ended March 31, 2018 compared to the three months ended March 31, 2017

Results of Operations

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

In thousands, except sales price data	Three months ended March 31, 2018	2017
Crude oil and natural gas sales	$1,113,852	$633,850
Gain on natural gas derivatives, net	10,174	46,858
Crude oil and natural gas service operations	17,002	4,719
Total revenues	1,141,028	685,427
Operating costs and expenses	(760,306)	(608,206)
Other expenses, net	(75,240)	(70,730)
Income before income taxes	305,482	6,491
Provision for income taxes	(71,536)	(6,022)
Net income	$233,946	$469
Production volumes:		
Crude oil (MBbl)	14,745	10,728
Natural gas (MMcf)	66,730	51,059
Crude oil equivalents (MBoe)	25,867	19,238
Sales volumes:		
Crude oil (MBbl)	14,682	10,754
Natural gas (MMcf)	66,730	51,059
Crude oil equivalents (MBoe)	25,804	19,264

Production

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

	Three months ended March 31, 2018 Volume	Percent	2017 Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	14,745	57 %	10,728	56 %	4,017	37 %
Natural gas (MMcf)	66,730	43 %	51,059	44 %	15,671	31 %
Total (MBoe)	25,867	100 %	19,238	100 %	6,629	34 %

	Three months ended March 31, 2018 MBoe	Percent	2017 MBoe	Percent	Volume increase	Volume percent increase
North Region	15,400	60 %	10,747	56 %	4,653	43 %
South Region	10,467	40 %	8,491	44 %	1,976	23 %
Total	25,867	100 %	19,238	100 %	6,629	34 %

The 37% increase in crude oil production for the 2018 first quarter was primarily driven by a 3,756 MBbls, or 52%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities, the timing of production commencing from new pad development projects, and improved initial production results being achieved on new wells resulting from optimized completion technologies. Additionally, production from our South region properties in the STACK play increased 478 MBbls, or 89%, from the prior year first quarter due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in that area. These increases were partially offset by decreased production from our North region properties in Montana Bakken and the Red River units due to natural declines in production. Montana Bakken crude oil production decreased 95 MBbls, or 16%, while crude oil production in the Red River units decreased 67 MBbls, or 8%, from the prior year first quarter.

The 31% increase in natural gas production for the 2018 first quarter was driven by increased production from our properties in the STACK play due to additional wells being completed and producing subsequent to March 31, 2017. Natural gas production in STACK increased 10,172 MMcf, or 81%, over the prior year first quarter. Additionally, natural gas production in North Dakota Bakken increased 6,348 MMcf, or 56%, in conjunction with the aforementioned increase in crude oil production over the prior year first quarter. These increases were partially offset by reduced production from various other areas in our North and South regions due to property dispositions, natural declines in production, and limited drilling activities over the past year.

In conjunction with our planned increase in capital spending for 2018, we expect our production will average between 285,000 and 300,000 Boe per day for full year 2018 compared to average daily production of 287,410 Boe per day for the 2018 first quarter and 242,637 Boe per day for full year 2017.

Revenues

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

Net crude oil and natural gas sales and related net sales prices presented below are non-GAAP measures for the three months ended March 31, 2018. See the previous section titled Change in presentation of revenues for discussion and calculation of these measures.

Net crude oil and natural gas sales. Net crude oil and natural gas sales were $1,064.6 million for the first quarter of 2018, a 68% increase from sales of $633.9 million for the 2017 first quarter due to increases in crude oil net sales prices and total sales volumes.

Our crude oil net sales prices averaged $58.98 per barrel in the 2018 first quarter, an increase of 32% compared to $44.69 per barrel for the 2017 first quarter due to higher crude oil market prices and significantly improved price realizations. The differential between NYMEX West Texas Intermediate calendar month prices and our realized crude oil net sales prices averaged $3.91 per barrel for the 2018 first quarter compared to $7.09 per barrel for the 2017 first quarter. The improved differential was due to the amendment of an existing third party transportation arrangement that resulted in lower per-barrel fees charged to the Company, effective January 1, 2018, along with growth in our South region production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma.

Our natural gas net sales prices averaged $2.98 per Mcf for the 2018 first quarter compared to $3.00 per Mcf for the 2017 first quarter. The discount between our realized natural gas net sales prices and NYMEX Henry Hub calendar month prices improved by $0.29 per Mcf compared to the 2017 first quarter. We sell the majority of our operated natural gas production to midstream customers at lease locations under multi-year term contracts based on market prices in the field where the sales occur. The field markets are impacted by residue gas and natural gas liquids ("NGLs") prices at secondary, downstream markets. NGL prices have generally increased over prior year levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream relative to benchmark prices compared to the prior year first quarter.

Total sales volumes for the first quarter of 2018 increased 6,540 MBoe, or 34%, compared to the 2017 first quarter, reflecting an increase in our pace of drilling and completion activities over the past year. For the first quarter of 2018, our crude oil sales volumes increased 37% from the comparable 2017 period, while our natural gas sales volumes increased 31%.

Derivatives. Changes in natural gas prices during the first quarter of 2018 had a favorable impact on the fair value of our natural gas derivatives, which resulted in positive revenue adjustments of $10.2 million for the period, representing $4.2 million of cash gains coupled with $6.0 million of non-cash gains. Our revenues for the remainder of 2018 may be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in natural gas prices.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of crude oil reclaimed from waste products. Revenues associated with such activities increased $12.3 million from $4.7 million for the first quarter of 2017 to $17.0 million for the first quarter of 2018 due to changes in the nature, timing and extent of water handling and recycling activities between periods.

Operating Costs and Expenses

Production Expenses. Production expenses increased $20.1 million, or 28%, from $72.9 million for the first quarter of 2017 to $93.0 million for the first quarter of 2018 due to an increase in the number of producing wells and related 34% increase in production volumes. Production expenses on a per-Boe basis decreased to $3.60 for the 2018 first quarter compared to $3.78 for the 2017 first quarter which included higher than normal expenses associated with severe winter weather conditions in the North region.

Production Taxes. Production taxes increased $39.4 million, or 95%, to $80.6 million for the first quarter of 2018 compared to $41.2 million for the first quarter of 2017 primarily due to higher crude oil and natural gas sales. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of net crude oil and natural gas sales were 7.6% for the first quarter of 2018 compared to 6.5% for the first quarter of 2017. This increase was due in part to a significant increase in production and revenues generated in North Dakota from increased well completion activities over the past year, which has higher production tax rates compared to Oklahoma. Additionally, in 2017 legislation was enacted in Oklahoma that increased the production tax rate from 1% to 4% (effective July 1, 2017) and again from 4% to 7% (effective December 1, 2017) on wells that began producing between July 1, 2011 and July 1, 2015, which contributed to the increase in our average production tax rate for the first quarter of 2018. In March 2018, new legislation was enacted again in Oklahoma that increased the state's production tax rate, effective July 1, 2018, from 2% to 5% for the first 36 months of production for wells commencing production after July 1, 2015, which is expected to result in increased production taxes owed in future periods, the impact of which is uncertain.

Transportation Expenses. See Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues for discussion of our January 1, 2018 implementation of new revenue recognition and presentations rules that gave rise to the presentation of transportation expenses in the 2018 first quarter.

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

	Three months ended March 31,	
In thousands	2018	2017
Geological and geophysical costs	$1,719	$4,841
Exploratory dry hole costs	1	157
Exploration expenses	$1,720	$4,998

Depreciation, Depletion, Amortization and Accretion ("DD&A"). Total DD&A increased $72.2 million, or 19%, to $454.4 million for the first quarter of 2018 compared to $382.2 million for the first quarter of 2017 due to an increase in total sales volumes which was partially offset by the impact from an increase in the volume of proved reserves over which costs are depleted as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Three months ended March 31,	
$/Boe	2018	2017
Crude oil and natural gas	$17.35	$19.43
Other equipment	0.20	0.34
Asset retirement obligation accretion	0.06	0.07
Depreciation, depletion, amortization and accretion	$17.61	$19.84

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense increases. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense decreases. Upward revisions to proved reserves over the past year due in part to an improvement in commodity prices contributed to a decrease in our

DD&A rate for crude oil and natural gas properties in the first quarter of 2018 compared to the first quarter of 2017. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in an improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in the current period.

Property Impairments. Total property impairments decreased $17.6 million, or 34%, to $33.8 million for the 2018 first quarter compared to $51.4 million for the 2017 first quarter primarily due to a decrease in non-producing property impairments.

Impairments of non-producing properties decreased $16.7 million, or 33%, to $33.8 million for the 2018 first quarter compared to $50.5 million for the 2017 first quarter. This decrease was due to a lower balance of unamortized leasehold costs in the current period and a reduction over the past year in the Company's estimates of undeveloped properties not expected to be developed prior to lease expiration due to an increase in the allocation of capital to development drilling activities in 2017 and 2018.
There were no proved property impairments recognized in the 2018 first quarter compared to $0.9 million of such impairments for the first quarter of 2017.
General and Administrative ("G&A") Expenses. Total G&A expenses decreased $4.2 million, or 9%, from $47.2 million for the first quarter of 2017 to $43.0 million for the first quarter of 2018. Total G&A expenses include non-cash charges for equity compensation of $10.9 million and $11.4 million for the first quarters of 2018 and 2017, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $32.1 million for the 2018 first quarter, a decrease of $3.7 million, or 10%, compared to $35.8 million for the 2017 first quarter. This decrease primarily resulted from higher overhead recoveries from joint interest owners driven by increased completion activities over the prior period.
The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

	Three months ended March 31,	
$/Boe	2018	2017
General and administrative expenses	$1.25	$1.86
Non-cash equity compensation	0.42	0.59
Total general and administrative expenses	$1.67	$2.45

The decrease in G&A expenses other than equity compensation on a per-Boe basis was driven by the aforementioned increase in overhead recoveries along with a 34% increase in total sales volumes from new well completions with no comparable increase in G&A expenses.
The decrease in equity compensation expense on a per-Boe basis resulted from changes in the timing and magnitude of forfeitures of unvested restricted stock between periods, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.
Interest Expense. Interest expense increased $4.7 million, or 7%, to $75.9 million for the first quarter of 2018 compared to $71.2 million for the first quarter of 2017 due to an increase in the weighted average interest rate on our debt resulting from higher market interest rates on variable-rate credit facility borrowings along with our December 2017 issuance of $1.0 billion of 4.375% Senior Notes due 2028, the proceeds of which were used to refinance lower-rate borrowings having shorter maturities. This increase was partially offset by lower interest expense resulting from a decrease in total outstanding debt in the current period. Our weighted average outstanding long-term debt balance for the 2018 first quarter was approximately $6.4 billion with a weighted average interest rate of 4.5%, compared to averages of $6.6 billion and 4.2% for the 2017 first quarter.
Our new credit facility has lender commitments totaling $1.5 billion compared to commitments of $2.75 billion under our previous credit facility. We incur commitment fees on the daily average amount of unused borrowing availability, which are included within "Interest Expense". The commitment fee rate under our new credit facility is 0.20% based on currently assigned credit ratings. The reduced commitments under our new credit facility are expected to result in lower commitment fees compared to prior periods, the extent of which is uncertain.
Income Taxes. For the first quarters of 2018 and 2017 we provided for income taxes at a combined federal and state tax rate of 24% and 38%, respectively, of pre-tax income generated by our operations in the United States. We recorded an income tax provision for the first quarter of 2018 of $71.5 million compared to a provision of $6.0 million for the first quarter of 2017, which resulted in effective tax rates of 23% and 93%, respectively, after taking into account statutory tax rates, permanent taxable differences, tax effects from stock-based compensation, valuation allowances, and other items. Our tax provision for the 2018 first quarter reflects our application of the Tax Cuts and Jobs Act that was signed into law in December 2017, which among other things reduced the U.S. federal corporate

income tax rate from 35% to 21% effective January 1, 2018. See Notes to Unaudited Condensed Consolidated Financial Statements–Note 11. Income Taxes for a summary of the sources and tax effects of items comprising our effective tax rate for the first quarters of 2018 and 2017.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt securities. Additionally, in recent years non-strategic asset dispositions 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 2018 capital expenditure budget, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our revolving credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of March 31, 2018, including those described in Note 8. 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

Our net cash provided by operating activities totaled $886.2 million and $470.2 million for the three months ended March 31, 2018 and 2017, respectively. The increase in operating cash flows was primarily due to an increase in crude oil and natural gas revenues driven by higher realized crude oil net sales prices and total sales volumes in 2018, the effects of which were partially offset by increases in production expenses, production taxes, and interest expenses.

Cash flows used in investing activities

During the three months ended March 31, 2018 and 2017, we had cash flows used in investing activities of $628.2 million and $389.3 million, respectively. These totals include cash capital expenditures of $628.3 million and $395.1 million, respectively, inclusive of exploration and development drilling, property acquisitions, and dry hole costs. Property acquisitions totaled $30.6 million and $13.4 million for the three months ended March 31, 2018 and 2017, respectively. The increase in capital spending was driven by an increase in our capital budget and related drilling and completion activities in 2018. Our non-acquisition capital expenditures for full year 2018 are budgeted to be $2.3 billion compared to $2.0 billion of non-acquisition capital spending for full year 2017.

Cash flows used in financing activities

Net cash used in financing activities for the three months ended March 31, 2018 and 2017 totaled $203.7 million and $80.4 million, respectively, primarily resulting from $188 million and $70 million, respectively, of net repayments on our revolving 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 revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments for at least the next 12 months.

Our planned 2018 capital expenditures are expected to be funded entirely from operating cash flows. Additionally, under the current commodity price environment we expect to generate significant cash flows in excess of operating and capital needs in 2018, which we plan to apply toward further reduction of debt in the future.

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

Revolving credit facility

On April 9, 2018, we entered into a new unsecured revolving credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. In connection with the execution of the new credit facility, we terminated our then-existing $2.75 billion credit facility that was due to mature in May 2019.

As of April 30, 2018, we had no outstanding borrowings and approximately $1.5 billion of borrowing availability on our new 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.

Our new credit facility retains substantially the same restrictive covenants as our previous credit facility, including 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, and a financial covenant that requires us to 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.

We were in compliance with our credit facility covenants as in effect at March 31, 2018 and expect to maintain compliance under our new credit facility for at least the next 12 months. At March 31, 2018, our consolidated net debt to total capitalization ratio was 0.49 to 1.00. We do not believe the revolving 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. At March 31, 2018, our total debt would have needed to independently increase by approximately $5.9 billion above the existing level at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $3.2 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at March 31, 2018 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Joint development agreement funding

In September 2014, we entered into an agreement with a U.S. subsidiary of SK E&S Co. Ltd ("SK") of South Korea to jointly develop a portion of the Company's STACK properties. Pursuant to the agreement, SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest in the STACK play until approximately $270 million has been expended by SK on our behalf. As of March 31, 2018, approximately $76 million of the carry had yet to be realized and is expected to be realized through mid-2019.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $6.2 billion at March 31, 2018. We have no near-term senior note maturities, with our earliest scheduled senior note maturity being our $2.0 billion of 2022 Notes due in September 2022. 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.

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

Three of our subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes as of March 31, 2018.

Capital expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas. Acquisition expenditures are not budgeted.

Our capital expenditures budget for 2018 is $2.3 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$ 1,988
Land costs	132
Capital facilities, workovers and other corporate assets	168
Seismic	12
Total 2018 capital budget, excluding acquisitions	$ 2,300

For the three months ended March 31, 2018, we invested $596.3 million in our capital program excluding $30.6 million of unbudgeted acquisitions and $1.3 million of capital costs associated with decreased accruals for capital expenditures. Our 2018 year to date capital expenditures were allocated as follows:

In millions	1Q 2018
Exploration and development drilling	$496.3
Land costs	67.0
Capital facilities, workovers and other corporate assets	33.0
Seismic	—
Capital expenditures, excluding acquisitions	596.3
Acquisitions of producing properties	2.6
Acquisitions of non-producing properties	28.0
Total acquisitions	30.6
Total capital expenditures	$626.9

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, access to capital, 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 capital spending plans 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 8. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of certain future commitments and contingencies of the Company as of March 31, 2018. We believe our cash flows from operations, our remaining cash balance, and amounts available under our revolving 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

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.

29

Revenues

On January 1, 2018 we adopted Accounting Standards Update 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), which impacted the presentation of our crude oil and natural gas revenues. For the sale of crude oil and natural gas, we evaluate whether we are the principal, and report revenues on a gross basis, or an agent, and report revenues on a net basis. In this assessment, we consider if we obtain control of the products before they are transferred to the customer as well as other indicators.

See Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues for discussion of the impact from adoption of ASU 2016-08. There have been no other changes in our application of critical accounting policies from those disclosed in our 2017 Form 10-K.

New Accounting Pronouncements

See Notes to Unaudited Condensed Consolidated Financial Statements–Note 2. Basis of Presentation and Significant Accounting Policies for a discussion of the new revenue recognition and presentation pronouncements adopted on January 1, 2018 along with a discussion of accounting pronouncements not yet adopted.

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, 2018, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $598 million for each $10.00 per barrel change in crude oil prices at March 31, 2018 and $271 million for each $1.00 per Mcf change in natural gas prices at March 31, 2018.

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 2018. Our future crude oil production, and future natural gas production beyond December 2018, 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, 2018 had an overall favorable impact on the fair value of our derivative instruments. For the three months ended March 31, 2018, we recognized cash gains on natural gas derivatives of $4.2 million and non-cash mark-to-market gains on natural gas derivatives of $6.0 million. The fair value of our natural gas derivative instruments at March 31, 2018 was a net asset of $8.6 million. An assumed increase in the forward prices used in the March 31, 2018 valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $145 million at March 31, 2018. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $162 million at March 31, 2018. Changes in the fair value of our natural gas derivatives from the above price sensitivities would produce a corresponding change in our total revenues.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($643 million in receivables at March 31, 2018); our joint interest and other receivables ($417 million at March 31, 2018); and counterparty credit risk associated with our derivative instrument receivables ($9 million at March 31, 2018).

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

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $47 million at March 31, 2018, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on a co-owner's interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

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

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to variable-rate borrowings, if any, we may have outstanding from time to time under our revolving credit facility. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. 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 revolving credit facility at April 30, 2018.

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, 2018 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the three months ended March 31, 2018, 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 8. 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.

We have received Notices of Violation from the North Dakota Department of Health ("NDDH") alleging violations of the state's air quality and water pollution control laws and rules. We exchanged information and engaged in discussions with NDDH aimed at resolving the allegations and anticipate further discussions and exchanges. Resolution of the allegations may result in monetary sanctions exceeding $100,000.

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 2017 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 2017 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 2017 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, 2018:

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, 2018 to January 31, 2018	—		$ —		—	—
February 1, 2018 to February 28, 2018	375,136	(2)	$ 52.84	(2)	—	—
March 1, 2018 to March 31, 2018	57,881	(3)	$ 49.57	(3)	—	—
Total	433,017		$ 52.41		—	—

(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, 276,108 shares represent shares surrendered by employees to cover tax liabilities at an average price per share of $53.77. 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 99,028 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 $50.26.

(3) Represents 57,881 shares of our common stock purchased by Harold G. Hamm in open-market transactions at an average price per share of $49.57.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

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.
4.1***	Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee.
10.1*†	Description of cash bonus plan updated as of March 19, 2018.
10.2***†	Continental Resources, Inc. 2013 Long-Term Incentive Plan.
10.3	Revolving Credit Agreement dated as of April 9, 2018 among Continental Resources, Inc., as borrower, and its subsidiaries Banner Pipeline Company L.L.C., CLR Asset Holdings, LLC and The Mineral Resources Company as guarantors, MUFG Union Bank, N.A., as Administrative Agent, MUFG Union Bank, N.A., Merrill Lynch, Pierce, Fenner & Smith Incorporated, TD Securities (USA) LLC and Mizuho Bank, Ltd., as Joint Lead Arrangers and Joint Bookrunners, Compass Bank, Citibank, N.A., Export Development Canada, ING Bank, JPMorgan Chase Bank, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A., as Co-Documentation Agents and the other lenders named therein filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 12, 2018 and incorporated herein by reference.
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

***Re-filed herewith pursuant to Item 10(d) of Regulation S-K.

† 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:	May 2, 2018	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer
			(Duly Authorized Officer and Principal Financial Officer)