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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2021

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)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No ☐

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

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

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

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

367,534,598 shares of our $0.01 par value common stock were outstanding on April 21, 2021.

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

Glossary of Crude Oil and Natural Gas Terms

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

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

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

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

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

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

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

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

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

"field" An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

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

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

"MBoe" One thousand Boe.

"Mcf" One thousand cubic feet of natural gas.

"MMBoe" One million Boe.

"MMBtu" One million British thermal units.

"MMcf" One million cubic feet of natural gas.

"*net acres*" or "*net wells*" Refers to the sum of the fractional working interests owned in gross acres or gross wells.

"*Net crude oil and natural gas sales*" Represents total crude oil and natural gas sales less total transportation expenses. Net crude oil and natural gas sales presented herein are non-GAAP measures. See *Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for a discussion and calculation of this measure.

"*Net sales price*" Represents the average net wellhead sales price received by the Company for its crude oil or natural gas sales after deducting transportation expenses. Net sales price is calculated by taking revenues less transportation expenses divided by sales volumes for a period, whether for crude oil or natural gas, as applicable. Net sales prices presented herein are non-GAAP measures. See *Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures* for a discussion and calculation of this measure.

"NYMEX" The New York Mercantile Exchange.

“play” A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

“proved reserves” The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.

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

“royalty interest” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

“SCOOP” Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.

"STACK" Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma.

“undeveloped acreage” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

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

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

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

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

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- future crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- shutting in of production and the resumption of production activities;
- 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, dividend payments, bond repurchases, debt reduction plans, or share repurchases;
- the impact of the COVID-19 (novel coronavirus) pandemic on economic conditions, the demand for crude oil, the Company's operations and the operations of its customers, suppliers, and service providers;
- 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, 2020, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Many of the foregoing risks and uncertainties have been, and may further be, exacerbated by the COVID-19 pandemic and any consequent worsening of the global economic environment. New factors emerge from time to time, and it is not possible for us to predict all such factors. 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 for the year ended December 31, 2020 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, 2021 *(Unaudited)*	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 96,057	$ 47,470
Receivables:		
Crude oil and natural gas sales	690,619	561,127
Joint interest and other	171,465	143,829
Allowance for credit losses	(2,700)	(2,462)
Receivables, net	859,384	702,494
Derivative assets	11,275	15,303
Inventories	76,008	72,157
Prepaid expenses and other	19,097	15,121
Total current assets	1,061,821	852,545
Net property and equipment, based on successful efforts method of accounting	13,724,418	13,737,292
Operating lease right-of-use assets	22,863	8,557
Other noncurrent assets	11,825	34,704
Total assets	$ 14,820,927	$ 14,633,098
Liabilities and equity		
Current liabilities:		
Accounts payable trade	$ 509,490	$ 361,704
Revenues and royalties payable	501,013	327,029
Accrued liabilities and other	203,675	167,013
Derivative liabilities	10,659	227
Current portion of operating lease liabilities	5,140	2,588
Current portion of long-term debt	2,265	2,245
Total current liabilities	1,232,242	860,806
Long-term debt, net of current portion	4,971,055	5,530,173
Other noncurrent liabilities:		
Deferred income tax liabilities, net	1,700,682	1,620,154
Asset retirement obligations, net of current portion	186,014	177,194
Derivative liabilities, noncurrent	1,194	1,584
Operating lease liabilities, net of current portion	17,559	5,839
Other noncurrent liabilities	14,975	14,623
Total other noncurrent liabilities	1,920,424	1,819,394
Commitments and contingencies (Note 8)		
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; 367,491,013 shares issued and outstanding at March 31, 2021; 365,220,435 shares issued and outstanding at December 31, 2020	3,675	3,652
Additional paid-in capital	1,213,115	1,205,148
Retained earnings	5,107,288	4,847,646
Total shareholders' equity attributable to Continental Resources	6,324,078	6,056,446
Noncontrolling interests	373,128	366,279
Total equity	6,697,206	6,422,725
Total liabilities and equity	$ 14,820,927	$ 14,633,098

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

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

In thousands, except per share data	Three months ended March 31, 2021	2020
Revenues:		
Crude oil and natural gas sales	$ 1,247,533	$ 862,743
Loss on derivative instruments, net	(43,507)	—
Crude oil and natural gas service operations	11,789	18,058
Total revenues	1,215,815	880,801
Operating costs and expenses:		
Production expenses	93,065	118,478
Production taxes	83,976	71,224
Transportation expenses	50,256	60,502
Exploration expenses	4,645	11,637
Crude oil and natural gas service operations	4,490	5,910
Depreciation, depletion, amortization and accretion	509,608	536,696
Property impairments	11,436	222,529
General and administrative expenses	52,848	42,911
Net (gain) loss on sale of assets and other	(207)	4,502
Total operating costs and expenses	810,117	1,074,389
Income (loss) from operations	405,698	(193,588)
Other income (expense):		
Interest expense	(64,951)	(63,594)
Gain (loss) on extinguishment of debt	(196)	17,631
Other	252	532
	(64,895)	(45,431)
Income (loss) before income taxes	340,803	(239,019)
(Provision) benefit for income taxes	(80,528)	52,235
Net income (loss)	260,275	(186,784)
Net income (loss) attributable to noncontrolling interests	633	(1,120)
Net income (loss) attributable to Continental Resources	$ 259,642	$ (185,664)
Net income (loss) per share attributable to Continental Resources:		
Basic	$ 0.72	$ (0.51)
Diluted	$ 0.72	$ (0.51)

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

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

Three months ended March 31, 2021	Shareholders' equity attributable to Continental Resources							
In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Treasury stock	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
Balance at December 31, 2020	365,220,435	$ 3,652	$ 1,205,148	$ —	$ 4,847,646	$ 6,056,446	$ 366,279	$ 6,422,725
Net income	—	—	—	—	259,642	259,642	633	260,275
Stock-based compensation	—	—	16,900	—	—	16,900	—	16,900
Restricted stock:								
Granted	2,726,442	27	—	—	—	27	—	27
Repurchased and canceled	(390,484)	(3)	(8,933)	—	—	(8,936)	—	(8,936)
Forfeited	(65,380)	(1)	—	—	—	(1)	—	(1)
Contributions from noncontrolling interests	—	—	—	—	—	—	11,463	11,463
Distributions to noncontrolling interests	—	—	—	—	—	—	(5,247)	(5,247)
Balance at March 31, 2021	367,491,013	$ 3,675	$ 1,213,115	$ —	$ 5,107,288	$ 6,324,078	$ 373,128	$ 6,697,206

Three months ended March 31, 2020	Shareholders' equity attributable to Continental Resources							
In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Treasury stock	Retained earnings	Total shareholders' equity of Continental Resources	Noncontrolling interests	Total equity
Balance at December 31, 2019	371,074,036	$ 3,711	$ 1,274,732	$ —	$ 5,463,224	$ 6,741,667	$ 366,684	$ 7,108,351
Net income (loss)	—	—	—	—	(185,664)	(185,664)	(1,120)	(186,784)
Cumulative effect adjustment from adoption of ASU 2016-13	—	—	—	—	(137)	(137)	—	(137)
Cash dividends declared ($0.05 per share)	—	—	—	—	(18,580)	(18,580)	—	(18,580)
Change in dividends payable	—	—	—	—	2	2	—	2
Common stock repurchased	—	—	—	(126,906)	—	(126,906)	—	(126,906)
Common stock retired	(8,122,104)	(81)	(126,825)	126,906	—	—	—	—
Stock-based compensation	—	—	16,411	—	—	16,411	—	16,411
Restricted stock:								
Granted	2,454,235	24	—	—	—	24	—	24
Repurchased and canceled	(246,346)	(2)	(6,452)	—	—	(6,454)	—	(6,454)
Forfeited	(42,818)	(1)	—	—	—	(1)	—	(1)
Contributions from noncontrolling interests	—	—	—	—	—	—	16,950	16,950
Distributions to noncontrolling interests	—	—	—	—	—	—	(5,618)	(5,618)
Balance at March 31, 2020	365,117,003	$ 3,651	$ 1,157,866	$ —	$ 5,258,845	$ 6,420,362	$ 376,896	$ 6,797,258

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

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

In thousands	Three months ended March 31, 2021	2020
Cash flows from operating activities		
Net income (loss)	$ 260,275	$ (186,784)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	508,327	536,786
Property impairments	11,436	222,529
Non-cash loss on derivatives	14,070	—
Stock-based compensation	16,927	16,441
Provision (benefit) for deferred income taxes	80,528	(50,012)
Dry hole costs	—	6,259
Net (gain) loss on sale of assets and other	(207)	4,502
(Gain) loss on extinguishment of debt	196	(17,631)
Other, net	2,664	2,911
Changes in assets and liabilities:		
Accounts receivable	(156,860)	344,845
Inventories	(3,851)	22,417
Other current assets	(2,336)	(4,848)
Accounts payable trade	98,521	70,084
Revenues and royalties payable	173,648	(231,990)
Accrued liabilities and other	36,149	(70,274)
Other noncurrent assets and liabilities	773	(1,417)
Net cash provided by operating activities	1,040,260	663,818
Cash flows from investing activities		
Exploration and development	(258,758)	(673,191)
Purchase of producing crude oil and natural gas properties	(161,764)	(19,258)
Purchase of other property and equipment	(7,660)	(14,923)
Proceeds from sale of assets	98	633
Net cash used in investing activities	(428,084)	(706,739)
Cash flows from financing activities		
Credit facility borrowings	685,000	1,130,000
Repayment of credit facility	(845,000)	(450,000)
Redemption of Senior Notes	(400,000)	(22,527)
Repayment of other debt	(552)	(603)
Contributions from noncontrolling interests	10,937	21,254
Distributions to noncontrolling interests	(4,927)	(5,212)
Repurchase of common stock	—	(126,906)
Repurchase of restricted stock for tax withholdings	(8,936)	(6,454)
Dividends paid on common stock	(111)	(18,460)
Net cash provided by (used in) financing activities	(563,589)	521,092
Net change in cash and cash equivalents	48,587	478,171
Cash and cash equivalents at beginning of period	47,470	39,400
Cash and cash equivalents at end of period	$ 96,057	$ 517,571

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

Note 1. Organization and Nature of Business

Continental Resources, Inc. (the “Company”) was formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company’s principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. Additionally, the Company pursues the acquisition and management of perpetually owned minerals located in certain of its key operating areas. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, Wyoming Powder River Basin, 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.

The Company's operations in the North region comprised 55% of its crude oil and natural gas production and 55% of its crude oil and natural gas revenues for the three months ended March 31, 2021. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. The Company's operations in the South region comprised 45% of its crude oil and natural gas production and 45% of its crude oil and natural gas revenues for the three months ended March 31, 2021. The Company's principal producing properties in the South region are located in the SCOOP and STACK areas of Oklahoma.

For the three months ended March 31, 2021, crude oil accounted for 49% of the Company’s total production and 62% of its crude oil and natural gas revenues.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The condensed consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries, and entities in which the Company has a controlling financial interest. Intercompany accounts and transactions have been eliminated upon consolidation. Noncontrolling interests reflected herein represent third party ownership in the net assets of consolidated subsidiaries. The portions of consolidated net income (loss) and equity attributable to the noncontrolling interests are presented separately in the Company’s financial statements.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the “SEC”) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States (“U.S. GAAP”), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Quarterly Report on Form 10-Q (“Form 10-Q”) together with the Company’s Annual Report on Form 10-K for the year ended December 31, 2020 (“2020 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, 2021 and for the three month periods ended March 31, 2021 and 2020 are unaudited. The condensed consolidated balance sheet as of December 31, 2020 was derived from the audited balance sheet included in the 2020 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these condensed consolidated financial statements.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates. The most significant estimates and assumptions impacting reported results are estimates of the Company’s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these unaudited condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations that may be expected for any other interim period or for an entire year.

Earnings per share

Basic net income (loss) per share is computed by dividing net income (loss) attributable to the Company by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects the potential dilution of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share attributable to the Company for the three months ended March 31, 2021 and 2020.

	Three months ended March 31,	
In thousands, except per share data	**2021**	**2020**
Net income (loss) attributable to Continental Resources (numerator)	$ 259,642	$ (185,664)
Weighted average shares (denominator):		
Weighted average shares - basic	360,789	365,403
Non-vested restricted stock (1)	1,884	—
Weighted average shares - diluted	362,673	365,403
Net income (loss) per share attributable to Continental Resources:		
Basic	$ 0.72	$ (0.51)
Diluted	$ 0.72	$ (0.51)

(1) For the three months ended March 31, 2020 the Company had a net loss and therefore the potential dilutive effect of approximately 594,000 weighted average non-vested restricted shares were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computation.

Credit risk

The Company's principal exposure to credit risk is through receivables associated with the sale of its crude oil and natural gas production and receivables associated with billings to joint interest owners. Accordingly, the Company classifies its receivables into two portfolio segments as depicted on the condensed consolidated balance sheets as "Receivables—Crude oil and natural gas sales” and "Receivables—Joint interest and other.” The Company determines its credit loss allowance for each portfolio segment by considering a number of factors, primarily including the Company’s history of credit losses with adjustment as needed to reflect current conditions, the length of time accounts are past due, whether amounts relate to operated properties or non-operated properties, the ability to recoup amounts owed through netting of production proceeds, the balance of co-owner prepayments if any, and a party's ability to pay. Historically, the Company's credit losses have been immaterial. There were no significant write-offs, recoveries, or changes in the Company's allowance for credit losses during the three month periods ended March 31, 2021 and 2020.

Inventories

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

The components of inventory as of March 31, 2021 and December 31, 2020 consisted of the following:

In thousands	**March 31, 2021**	**December 31, 2020**
Tubular goods and equipment	$ 13,341	$ 13,671
Crude oil and natural gas	62,667	58,486
Total	$ 76,008	$ 72,157

In the first quarter of 2020 the Company recognized a $24.5 million impairment to reduce its crude oil inventory to estimated net realizable value at March 31, 2020. The impairment is included in the caption “Property impairments” in the unaudited condensed consolidated statements of operations for the three month period ended March 31, 2020.

Adoption of new accounting pronouncement

On January 1, 2021 the Company adopted Accounting Standards Update ("ASU") 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes.* This standard eliminates certain exceptions to the guidance in Topic 740 related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period, and the recognition of deferred tax liabilities for outside basis differences. The new guidance also clarifies certain aspects of the existing guidance, among other things. The Company adopted the standard on a prospective basis, which did not have a material impact on its financial position, results of operations, or cash flows.

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	**2021**	**2020**
Supplemental cash flow information:		
Cash paid for interest	$ 42,554	$ 51,111
Cash paid for income taxes	—	8
Cash received for income tax refunds (1)	2	9,485
Non-cash investing activities:		
Asset retirement obligation additions and revisions, net	6,802	2,508

(1) Amount received in the 2020 period primarily represents alternative minimum tax refunds.

As of March 31, 2021 and December 31, 2020, the Company had $178.2 million and $128.8 million, respectively, of accrued capital expenditures included in “Net property and equipment” with an offsetting amount in “Accounts payable trade” in the condensed consolidated balance sheets.

As of March 31, 2021 and December 31, 2020, the Company had $0.6 million and $0.1 million, respectively, of accrued contributions from noncontrolling interests included in "Receivables–Joint interest and other" with an offsetting amount in "Equity–Noncontrolling interests" in the condensed consolidated balance sheets.

As of March 31, 2021 and December 31, 2020, the Company had $1.3 million and $1.0 million, respectively, of accrued distributions to noncontrolling interests included in "Revenues and royalties payable" with an offsetting amount in "Equity–Noncontrolling interests" in the condensed consolidated balance sheets.

Note 4. Revenues

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

Operated crude oil revenues – The Company pays third parties to transport the majority of its operated crude oil production from lease locations to downstream market centers, at which time the Company's customers take title and custody of the product in exchange for prices based on the particular market where the product was delivered. Operated crude oil revenues are recognized during the month in which control transfers to the customer and it is probable the Company will collect the consideration it is entitled to receive. Crude oil sales proceeds from operated properties are generally received by the Company within one month after the month in which a sale has occurred. Operated crude oil revenues are presented separately from transportation expenses as the Company controls the operated production prior to its transfer to customers. Transportation expenses associated with the Company's operated crude oil production totaled $40.1 million and $50.4 million for the three months ended March 31, 2021 and 2020, respectively.

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

Under certain arrangements, the Company has the right to take a volume of processed residue gas and/or NGLs in-kind at the tailgate of the midstream customer's processing plant in lieu of a monetary settlement for the sale of the Company's operated natural gas production. The Company currently takes certain processed residue gas volumes in kind in lieu of monetary settlement, but does not currently take NGL volumes. When the Company elects to take volumes in kind, it pays third parties to transport the processed products it took in-kind to downstream delivery points, where it then sells to customers at prices applicable to those downstream markets. In such situations, operated revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Operated sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, the Company's revenues include the pricing adjustments applied by the midstream processing entity according to the applicable contractual pricing formula, but exclude the transportation expenses the Company incurs to transport the processed products to downstream customers. Transportation expenses associated with these arrangements totaled $10.2 million and $10.1 million for the three months ended March 31, 2021 and 2020, respectively.

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

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

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

Disaggregation of crude oil and natural gas revenues

The following tables present the disaggregation of the Company's crude oil and natural gas revenues for the three months ended March 31, 2021 and 2020.

	Three months ended March 31, 2021			Three months ended March 31, 2020		
In thousands	**North Region**	**South Region**	**Total**	**North Region**	**South Region**	**Total**
Crude oil revenues:						
Operated properties	$ 444,665	$ 166,430	$ 611,095	$ 448,930	$ 179,176	$ 628,106
Non-operated properties	143,552	14,121	157,673	132,939	12,725	145,664
Total crude oil revenues	588,217	180,551	768,768	581,869	191,901	773,770
Natural gas revenues:						
Operated properties	82,933	371,761	454,694	11,588	72,306	83,894
Non-operated properties	12,600	11,471	24,071	1,720	3,359	5,079
Total natural gas revenues	95,533	383,232	478,765	13,308	75,665	88,973
Crude oil and natural gas sales	$ 683,750	$ 563,783	$ 1,247,533	$ 595,177	$ 267,566	$ 862,743
Timing of revenue recognition						
Goods transferred at a point in time	$ 683,750	$ 563,783	$ 1,247,533	$ 595,177	$ 267,566	$ 862,743
Goods transferred over time	—	—	—	—	—	—
	$ 683,750	$ 563,783	$ 1,247,533	$ 595,177	$ 267,566	$ 862,743

Performance obligations

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

All of the Company's outstanding crude oil sales contracts at March 31, 2021 are short-term in nature with contract terms of less than one year. For such contracts, the Company has utilized the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

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

Contract balances

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

Revenues from previously satisfied performance obligations

To record revenues for commodity sales, at the end of each month the Company estimates the amount of production delivered and sold to customers and the prices to be received for such sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer and are reflected in the financial statements within the caption "Crude oil and natural gas sales". Revenues recognized during the three months ended March 31, 2021 and 2020 related to performance obligations satisfied in prior reporting periods were not material.

Note 5. Derivative Instruments

From time to time the Company enters into crude oil and natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of production. The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its derivatives as hedges for accounting purposes and, as a result, marks such derivative instruments to fair value and recognizes the changes in fair value in the unaudited condensed consolidated statements of operations under the caption "Loss on derivative instruments, net".

The Company's derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate ("WTI") pricing and natural gas derivative settlements based on NYMEX Henry Hub pricing. The estimated fair value of derivative contracts 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*.

At March 31, 2021 the Company had outstanding derivative contracts as set forth in the tables below.

Natural gas derivatives

			Collars			
			Floors		Ceilings	
Period and Type of Contract	**MMBtus**	**Swaps Weighted Average Price**	**Range**	**Weighted Average Price**	**Range**	**Weighted Average Price**
April 2021 - December 2021						
Swaps - Henry Hub	45,178,000	$ 2.94				
Collars - Henry Hub	27,450,000		$2.50 - $2.60	$ 2.58	$3.06 - $3.43	$ 3.24

Crude oil derivatives

			Collars			
			Floors		Ceilings	
Period and Type of Contract	**Bbls**	**Swaps Weighted Average Price**	**Range**	**Weighted Average Price**	**Range**	**Weighted Average Price**
April 2021 - December 2021						
NYMEX Roll Swaps	8,250,000	$ 0.47				
April 2021 - May 2021						
Swaps - WTI	1,815,000	$ 54.64				
Collars - WTI	1,132,000		$50.00 - $53.00	$ 51.81	$55.10 - $63.05	$ 59.89
January 2022 - March 2022						
NYMEX Roll Swaps	675,000	$ 0.50				

Derivative gains and losses

Cash receipts and payments in the following table reflect the gains or losses on derivative contracts which matured during the applicable period, calculated as the difference between the contract price and the settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continued 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. The Company had no outstanding commodity derivative instruments as of March 31, 2020 and for the three months then ended.

	Three months ended March 31,	
In thousands	**2021**	**2020**
Cash received (paid) on derivatives:		
Crude oil fixed price swaps	$ (30,033)	$ —
Crude oil collars	(4,956)	—
Crude oil NYMEX roll swaps	159	—
Natural gas fixed price swaps	2,210	—
Natural gas collars	3,183	—
Cash received (paid) on derivatives, net	(29,437)	—
Non-cash gain (loss) on derivatives:		
Crude oil fixed price swaps	(8,206)	—
Crude oil collars	(2,076)	—
Crude oil NYMEX roll swaps	175	—
Natural gas fixed price swaps	6,086	—
Natural gas collars	(10,049)	—
Non-cash gain (loss) on derivatives, net	(14,070)	—
Loss on derivative instruments, net	$ (43,507)	$ —

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," "Derivative assets, noncurrent," "Derivative liabilities," and "Derivative liabilities, noncurrent" as applicable. Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the condensed consolidated balance sheets.

The following table presents the gross amounts of recognized 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, 2021	December 31, 2020
Commodity derivative assets:		
Gross amounts of recognized assets	$ 14,362	$ 15,900
Gross amounts offset on balance sheet	(3,087)	(597)
Net amounts of assets on balance sheet	11,275	15,303
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(14,940)	(2,408)
Gross amounts offset on balance sheet	3,087	597
Net amounts of liabilities on balance sheet	$ (11,853)	$ (1,811)

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, 2021	December 31, 2020
Derivative assets	$ 11,275	$ 15,303
Derivative assets, noncurrent	—	—
Net amounts of assets on balance sheet	11,275	15,303
Derivative liabilities	(10,659)	(227)
Derivative liabilities, noncurrent	(1,194)	(1,584)
Net amounts of liabilities on balance sheet	(11,853)	(1,811)
Total derivative assets (liabilities), net	$ (578)	$ 13,492

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.

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 table summarizes the valuation of derivative instruments by pricing levels that were accounted for at fair value on a recurring basis as of March 31, 2021 and December 31, 2020.

	Fair value measurements at March 31, 2021 using:			
In thousands	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets (liabilities):				
Swaps	$ —	$ (77)	$ —	$ (77)
Collars	—	(676)	—	(676)
NYMEX roll swaps	—	$ 175	—	$ 175
Total	$ —	$ (578)	$ —	$ (578)

	Fair value measurements at December 31, 2020 using:			
In thousands	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets (liabilities):				
Swaps	$ —	$ 2,043	$ —	$ 2,043
Collars	—	11,449	—	$ 11,449
Total	$ —	$ 13,492	$ —	$ 13,492

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. Significant unobservable inputs (Level 3) utilized in the determination of discounted future net cash flows include future commodity prices adjusted for differentials, forecasted production based on decline curve analysis, estimated future operating and development costs, property ownership interests, and a 10% discount rate. At March 31, 2021, the Company's commodity price assumptions were based on forward NYMEX strip prices through year-end 2025 and were then escalated at 3% per year thereafter. Operating cost assumptions were based on current costs escalated at 3% per year beginning in 2022.

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

For the three months ended March 31, 2021, estimated future net cash flows were determined to be in excess of cost basis, and therefore no impairment was recorded for the Company's proved crude oil and natural gas properties for the 2021 period.

For the three months ended March 31, 2020, 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 amounted to $181.0 million for the three months ended March 31, 2020, which reflect fair value adjustments on legacy properties in the Red River Units totaling $166.5 million and various non-core properties in the North and South regions totaling $14.5 million. The impaired properties were written down to their estimated fair value at the time of impairment of $145.6 million. Impairments for the three months ended March 31, 2020 also include a $24.5 million impairment to reduce the Company's crude oil inventory to estimated net realizable value at the time of impairment.

Certain unproved crude oil and natural gas properties were impaired during the three months ended March 31, 2021 and 2020, 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 operations.

	Three months ended March 31,	
In thousands	**2021**	**2020**
Proved property and inventory impairments	$ —	$ 205,545
Unproved property impairments	11,436	16,984
Total	$ 11,436	$ 222,529

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, 2021		December 31, 2020	
In thousands	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Debt:				
Credit facility	$ —	$ —	$ 160,000	$ 160,000
Notes payable	24,036	23,400	24,590	24,700
5% Senior Notes due 2022	230,684	230,600	630,470	632,900
4.5% Senior Notes due 2023	647,222	672,300	646,943	669,900
3.8% Senior Notes due 2024	907,203	933,900	906,922	939,500
4.375% Senior Notes due 2028	991,024	1,051,700	990,746	1,024,400
5.75% Senior Notes due 2031	1,481,237	1,685,200	1,480,879	1,651,900
4.9% Senior Notes due 2044	691,914	696,500	691,868	689,600
Total debt	$ 4,973,320	$ 5,293,600	$ 5,532,418	$ 5,792,900

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

The fair value of notes payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the notes payable and an assumed discount rate. The fair value of notes payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of notes 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"), the 5.75% Senior Notes due 2031 ("2031 Notes"), and the 4.9% Senior Notes due 2044 ("2044 Notes") are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

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

Note 7. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $42.2 million and $43.7 million at March 31, 2021 and December 31, 2020, respectively, consists of the following.

In thousands	March 31, 2021	December 31, 2020
Credit facility	$ —	$ 160,000
Notes payable	24,036	24,590
5% Senior Notes due 2022	230,684	630,470
4.5% Senior Notes due 2023	647,222	646,943
3.8% Senior Notes due 2024	907,203	906,922
4.375% Senior Notes due 2028	991,024	990,746
5.75% Senior Notes due 2031	1,481,237	1,480,879
4.9% Senior Notes due 2044	691,914	691,868
Total debt	$ 4,973,320	$ 5,532,418
Less: Current portion of long-term debt	2,265	2,245
Long-term debt, net of current portion	$ 4,971,055	$ 5,530,173

Credit Facility

The Company has an unsecured credit facility, maturing on April 9, 2023, with aggregate lender commitments totaling $1.5 billion. The Company had no outstanding borrowings on its credit facility at March 31, 2021.

Credit facility borrowings, if any, bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The Company incurs commitment fees based on currently assigned credit ratings of 0.25% per annum on the daily average amount of unused borrowing availability.

The credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the credit facility covenants at March 31, 2021.

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, 2021.

	2022 Notes	2023 Notes	2024 Notes	2028 Notes	2031 Notes	2044 Notes
Face value (in thousands)	$230,782	$649,625	$911,000	$1,000,000	$1,500,000	$700,000
Maturity date	Sep 15, 2022	April 15, 2023	June 1, 2024	January 15, 2028	January 15, 2031	June 1, 2044
Interest payment dates	Mar 15, Sep 15	April 15, Oct 15	June 1, Dec 1	Jan 15, July 15	Jan 15, Jul 15	June 1, Dec 1
Make-whole redemption period (1)	—	Jan 15, 2023	Mar 1, 2024	Oct 15, 2027	Jul 15, 2030	Dec 1, 2043

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

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

The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, or consolidate, merge or transfer certain assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at March 31, 2021.

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

Retirement of Senior Notes

2021

In January 2021, the Company redeemed $400 million principal amount of its outstanding 2022 Notes using proceeds from lower-rate borrowings on its credit facility. The Company recorded a pre-tax loss on extinguishment of debt related to the redemption of $0.2 million, which included the pro-rata write-off of deferred financing costs and unamortized debt premium associated with the redeemed notes. The loss is reflected in the caption "Gain (loss) on extinguishment of debt" in the unaudited condensed consolidated statements of operations.

Subsequent to March 31, 2021, the Company redeemed the remaining principal balance of its 2022 Notes as discussed in *Note 13. Subsequent Events*.

2020

In March 2020, the Company repurchased a portion of its 2023 Notes and 2024 Notes in open market transactions at a substantial discount to the face value of the notes, including $33.4 million face value of its 2023 Notes at an aggregate cost of $19.5 million and $7.0 million face value of its 2024 Notes at an aggregate cost of $3.8 million, in each case, including accrued and unpaid interest to the repurchase dates.

The repurchased notes were canceled by the Company. The Company recognized pre-tax gains on extinguishment of debt in the 2020 first quarter related to the March 2020 repurchases totaling $17.6 million, which included the pro-rata write-off of deferred financing costs and unamortized debt discount associated with the repurchased notes.

Notes payable

In June 2020, the Company borrowed an aggregate of $26.0 million under two 10-year amortizing term loans secured by the Company's corporate office building and its interest in parking facilities in Oklahoma City, Oklahoma. The loans mature in May 2030 and bear interest at a fixed rate of 3.50% per annum through June 9, 2025, at which time the interest rate will be reset and fixed through the maturity date. Principal and interest are payable monthly through the maturity date and, accordingly, $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, 2021 associated with the loans.

Note 8. Commitments and Contingencies

Included below is a discussion of certain future commitments of the Company as of March 31, 2021.

Drilling rig commitments – As of March 31, 2021, the Company has drilling rig contracts with various terms extending to November 2021. Future operating day-rate commitments as of March 31, 2021 total approximately $8 million, which will be incurred in the remainder of 2021. A portion of these future costs will be borne by other interest owners.

Transportation, gathering, and processing commitments – The Company has entered into transportation, gathering, 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 2031, require the Company to pay per-unit transportation, gathering, or processing charges regardless of the amount of capacity used. Future commitments remaining as of March 31, 2021 under the arrangements amount to approximately $1.46 billion, of which $192 million is expected to be incurred in the remainder of 2021, $272 million in 2022, $272 million in 2023, $234 million in 2024, $143 million in 2025, and $346 million thereafter. A portion of these future costs will be borne by other interest owners. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. These commitments do not qualify as leases under ASC Topic 842 and are not recognized on the Company's balance sheet.

Senior note redemption – On March 22, 2021, the Company announced its intention to redeem the remaining outstanding principal balance of its 2022 Notes subsequent to March 31, 2021. See *Note 13. Subsequent Events* for further discussion.

Litigation – The Company is involved in various legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of March 31, 2021 and December 31, 2020, the Company had recognized a liability within “Other noncurrent liabilities” of $7.7 million and $7.7 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 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, as amended ("2013 Plan"). The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the unaudited condensed consolidated statements of operations, was $16.9 million and $16.4 million for the three months ended March 31, 2021 and 2020, respectively.

In March 2019, the Company amended and restated its 2013 Plan and specified 12,983,543 shares of common stock may be issued pursuant to the amended plan. Subject to limited exceptions, the 2013 Plan allows previously issued shares to be reissued if such shares are subsequently forfeited or withheld to satisfy tax withholdings. As of March 31, 2021, the Company had 8,497,723 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 if any, subject to forfeiture. Restricted stock grants generally vest over periods ranging from 1 to 3 years.

A summary of changes in non-vested restricted shares outstanding for the three months ended March 31, 2021 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2020	4,890,638	$ 36.26
Granted	2,726,442	22.99
Vested	(1,278,334)	46.54
Forfeited	(65,380)	27.80
Non-vested restricted shares outstanding at March 31, 2021	6,273,366	$ 28.49

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, 2021 was approximately $29 million. As of March 31, 2021, there was approximately $111 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 2.0 years.

Note 10. Shareholders' Equity

Share repurchases

During the three months ended March 31, 2020, the Company repurchased and retired approximately 8.1 million shares of its common stock at an aggregate cost of $126.9 million. No share repurchases have been made subsequent to March 31, 2020. The Company has repurchased and retired a cumulative total of approximately 13.8 million shares at an aggregate cost of $317.1 million since the inception of its $1 billion share repurchase program in June 2019.

The timing and amount of the Company's share repurchases are subject to market conditions and management discretion. The share repurchase program does not require the Company to repurchase a specific number of shares and may be modified, suspended, or terminated by the Board of Directors at any time.

Dividend payment

On January 27, 2020 the Company declared a quarterly cash dividend of $0.05 per share on its outstanding common stock, which amounted to $18.4 million and was paid on February 21, 2020 to shareholders of record as of February 7, 2020.

See *Note 13. Subsequent Events* for discussion of a dividend declaration made by the Company subsequent to March 31, 2021.

Note 11. Income Taxes

Income taxes are accounted for using the asset and 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.

The Company's provision (benefit) for income taxes and resulting effective tax rates were as follows for the periods presented.

	Three months ended March 31,	
	2021	2020
Provision (benefit) for income taxes (in thousands)	$ 80,528	$ (52,235)
Effective tax rate	23.6 %	21.9 %

The Company computes its quarterly income tax provision (benefit) under the effective tax rate method based on applying an anticipated annual effective tax rate to year-to-date pre-tax income (loss), except for discrete items. Income taxes for discrete items are computed and recorded in the period in which the specific transaction occurs.

The Company's effective tax rate differs from the United States federal statutory tax rate due to the effect of state income taxes, equity compensation, changes in valuation allowances, and other tax items as reflected in the table below.

	Three months ended March 31,	
In thousands, except tax rates	2021	2020
Income (loss) before income taxes	$ 340,803	$ (239,019)
U.S. federal statutory tax rate	21.0 %	21.0 %
Expected income tax provision (benefit) based on U.S. federal statutory tax rate	71,569	(50,194)
Items impacting the effective tax rate:		
State and local income taxes, net of federal benefit	12,895	(7,603)
Equity compensation	5,990	3,886
Other, net	(5,031)	(3,189)
Change in valuation allowance	(4,895)	4,865
Provision (benefit) for income taxes	$ 80,528	$ (52,235)
Effective tax rate	23.6 %	21.9 %

In assessing the realizability of deferred tax assets the Company must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company applies judgment to determine the weight of both positive and negative evidence in order to conclude whether a valuation allowance is necessary for its deferred tax assets. In determining whether a valuation allowance is required, the Company considers, among other factors, the Company's financial position, results of operations, projected future taxable income, reversal of existing deferred tax liabilities against deferred tax assets, and tax planning strategies. During 2020, a valuation allowance of $14.5 million had been established for the deferred tax asset associated with a portion of the Company's Oklahoma state net operating loss carryforwards. In the first quarter of 2021, the Company reassessed the realizability of the deferred tax asset related to Oklahoma state net operating loss carryforwards and determined it was more likely than not that such assets would be realized. Therefore, it was determined that the previously recorded valuation allowance in 2020 should be released throughout 2021, with $4.9 million of the release being recognized during the first quarter of 2021.

The Company will continue to evaluate both the positive and negative evidence on a quarterly basis in determining the need for a valuation allowance with respect to its deferred tax assets. Changes in positive and negative evidence, including differences between estimated and actual results, could result in changes in the valuation of our deferred tax assets that could have a material impact on our consolidated financial statements. Changes in existing tax laws could also affect actual tax results and the realization of deferred tax assets over time.

Note 12. Property Acquisition

On March 4, 2021, the Company acquired undeveloped leasehold and producing properties in the Powder River Basin of Wyoming for $206.6 million, consisting of a $21.5 million escrow deposit paid in December 2020 upon execution of a definitive purchase agreement and a $185.1 million payment made at closing in March 2021. The acquisition included approximately 130,000 net acres and producing properties with production totaling approximately 7,200 net barrels of oil equivalent per day at the time of closing. The $21.5 million escrow deposit paid in December 2020 is included in the caption "Other noncurrent assets" on the Company's balance sheet at December 31, 2020, which was subsequently reclassified to "Net property and equipment" on the closing date. The Company recognized approximately $4.9 million of asset retirement obligations and $12.4 million of right-of-use assets and corresponding lease liabilities as of March 31, 2021 associated with the acquired properties.

Note 13. Subsequent Events

Full redemption of 2022 Notes

On April 22, 2021, the Company redeemed the remaining $230.8 million principal amount of its outstanding 2022 Notes using proceeds from lower-rate borrowings on its credit facility.

Dividend declaration

On April 27, 2021, the Company's Board of Directors approved the reinstatement of a quarterly dividend of $0.11 per share on the Company's outstanding common stock, payable on May 24, 2021 to shareholders of record as of May 10, 2021.

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

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Form 10-K for the year ended December 31, 2020.

The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described in *Part II, Item 1A. Risk Factors* included in this report, if any, and in our Form 10-K for the year ended December 31, 2020, 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.

Our crude oil and natural gas production and revenues for the first quarter of 2021 were impacted by severe winter weather and freezing temperatures in the southern United States in February 2021 as further discussed below and may not be indicative of future results.

Overview

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

First Quarter 2021 Highlights

Financial and operating highlights for the first quarter of 2021 are summarized below. Our first quarter results underscore our continued focus on maximizing cash flow generation, reducing debt, maintaining low-cost capital efficient operations, achieving consistent asset performance, and delivering shareholder capital returns.

- Generated $1.04 billion in cash flows from operations, a 57% increase over the 2020 first quarter;
- Reduced outstanding debt by $560 million, or 10%, in the first quarter;
- Continued to maintain low cost operations, with production expenses averaging $3.35 per Boe for the quarter;
- Completed acquisition of Powder River Basin properties in Wyoming for $207 million, adding 130,000 net acres and production of approximately 7,200 Boe per day as of the closing date; and
- Reinstated quarterly dividend in April 2021 at $0.11 per share of common stock to be paid on May 24, 2021.

Financial and Operating Metrics

The following table contains financial and operating metrics 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, 2021	Three months ended March 31, 2020
Average daily production:		
Crude oil (Bbl per day)	151,852	200,671
Natural gas (Mcf per day)	936,540	961,022
Crude oil equivalents (Boe per day)	307,942	360,841
Average net sales prices (1):		
Crude oil ($/Bbl)	$ 53.09	$ 39.64
Natural gas ($/Mcf)	$ 5.56	$ 0.90
Crude oil equivalents ($/Boe)	$ 43.11	$ 24.44
Crude oil net sales price discount to NYMEX ($/Bbl)	$ (4.52)	$ (6.26)
Natural gas net sales price premium (discount) to NYMEX ($/Mcf)	$ 2.87	$ (1.05)
Production expenses ($/Boe)	$ 3.35	$ 3.61
Production taxes (% of net crude oil and natural gas sales)	7.0 %	8.9 %
Depreciation, depletion, amortization and accretion ($/Boe)	$ 18.35	$ 16.35
Total general and administrative expenses ($/Boe)	$ 1.90	$ 1.31

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

Three months ended March 31, 2021 compared to the three months ended March 31, 2020

Results of Operations

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

In thousands	Three months ended March 31, 2021	Three months ended March 31, 2020
Crude oil and natural gas sales	$ 1,247,533	$ 862,743
Loss on derivative instruments, net	(43,507)	—
Crude oil and natural gas service operations	11,789	18,058
Total revenues	1,215,815	880,801
Operating costs and expenses	(810,117)	(1,074,389)
Other expenses, net	(64,895)	(45,431)
Income (loss) before income taxes	340,803	(239,019)
(Provision) benefit for income taxes	(80,528)	52,235
Net income (loss)	260,275	(186,784)
Net income (loss) attributable to noncontrolling interests	633	(1,120)
Net income (loss) attributable to Continental Resources	$ 259,642	$ (185,664)
Production volumes:		
Crude oil (MBbl)	13,667	18,261
Natural gas (MMcf)	84,289	87,453
Crude oil equivalents (MBoe)	27,715	32,836
Sales volumes:		
Crude oil (MBbl)	13,726	18,251
Natural gas (MMcf)	84,289	87,453
Crude oil equivalents (MBoe)	27,774	32,826

Production

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

Boe production per day	1Q 2021	1Q 2020	% Change
Bakken	160,577	201,502	(20 %)
SCOOP	101,984	107,817	(5 %)
STACK	36,402	44,155	(18 %)
All other	8,979	7,367	22 %
Total	307,942	360,841	(15 %)

In mid-February 2021, severe winter weather and freezing temperatures in the southern United States impacted our operations in Oklahoma, resulting in the curtailment of a portion of our production, delays in drilling and completion of wells, and other operational constraints, which adversely impacted our first quarter 2021 production by approximately 6,000 Boe per day (60% of which was crude oil). We have restored our curtailed production and estimate our production for the second quarter of 2021 will average between 160,000 and 165,000 barrels of oil per day and between 920,000 and 940,000 Mcf of natural gas per day.

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

	Three months ended March 31,					
	2021		2020			
	Volume	Percent	Volume	Percent	Volume decrease	Volume percent decrease
Crude oil (MBbl)	13,667	49 %	18,261	56 %	(4,594)	(25 %)
Natural gas (MMcf)	84,289	51 %	87,453	44 %	(3,164)	(4 %)
Total (MBoe)	27,715	100 %	32,836	100 %	(5,121)	(16 %)

	Three months ended March 31,					
	2021		2020			
	MBoe	Percent	MBoe	Percent	Volume decrease	Volume percent decrease
North Region	15,259	55 %	19,003	58 %	(3,744)	(20 %)
South Region	12,456	45 %	13,833	42 %	(1,377)	(10 %)
Total	27,715	100 %	32,836	100 %	(5,121)	(16 %)

The 25% decrease in crude oil production for the 2021 first quarter compared to the 2020 first quarter was driven by reduced drilling and completion activities over the past year in response to the economic turmoil from the COVID-19 pandemic coupled with the previously described weather-related production curtailments in February 2021, which led to a 3,514 MBbls, or 27%, decrease in Bakken crude oil production, a 985 MBbls, or 27%, decrease in SCOOP crude oil production, and a 183 MBbls, or 27%, decrease in STACK crude oil production compared to the 2020 first quarter.

The February 2021 production curtailments and limited drilling and completion activities over the past year also impacted our natural gas production, leading to a 4% decrease in natural gas production for the 2021 first quarter compared to the 2020 first quarter. Natural gas production in the Bakken decreased 2,222 MMcf, or 7%, and natural gas production in STACK decreased 3,351 MMcf, or 17%, from the prior year first quarter. These decreases were partially offset by a 2,115 MMcf, or 6%, increase in SCOOP natural gas production.

In the second quarter of 2020 we shifted our rigs to gas-weighted areas in Oklahoma to capitalize on improvements in market prices for natural gas. These actions contributed to an increase in our natural gas production as a percentage of total production in the 2021 first quarter compared to the 2020 first quarter. Based on drilling and completion plans, we project our production will become more oil-weighted in the second half of 2021 compared to the first half of the year.

Revenues

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

Net crude oil and natural gas sales. Net crude oil and natural gas sales totaled $1.20 billion for the first quarter of 2021, a 49% increase compared to net sales of $802.2 million for the 2020 first quarter due to significant increases in net sales prices partially offset by decreases in sales volumes as discussed below.

Total sales volumes for the first quarter of 2021 decreased 5,052 MBoe, or 15%, compared to the 2020 first quarter, reflecting the impact of reduced drilling and completion activities over the past year in response to economic turmoil from the COVID-19 pandemic and the previously described production curtailments in February 2021. For the first quarter of 2021, our crude oil sales volumes decreased 25% compared to the 2020 first quarter, while our natural gas sales volumes decreased 4%.

Our crude oil net sales prices averaged $53.09 per barrel in the 2021 first quarter, an increase of 34% compared to $39.64 per barrel for the 2020 first quarter due to an increase in market prices and improved price differentials. The differential between NYMEX West Texas Intermediate ("WTI") calendar month prices and our realized crude oil net sales prices averaged $4.52 per barrel for the 2021 first quarter compared to $6.26 per barrel for the 2020 first quarter. The 2020 first quarter price differential was impacted by adverse changes in supply and demand fundamentals from the early economic effects of COVID-19 and actions taken by the Organization of Petroleum Exporting Countries and Russia that negatively impacted location differentials and price realizations in the prior year first quarter.

Our natural gas net sales prices averaged $5.56 per Mcf for the 2021 first quarter compared to $0.90 per Mcf for the 2020 first quarter due to an increase in market prices and improved price differentials. The difference between our net sales prices and NYMEX Henry Hub calendar month natural gas prices was a premium of $2.87 per Mcf for the 2021 first quarter compared to a discount of $1.05 per Mcf for the 2020 first quarter. The effects of the previously described winter storm in February 2021 led to a period of increased spot prices for residue natural gas that resulted in a significant improvement in our price realizations in the 2021 first quarter relative to benchmark prices and prior periods. Additionally, prices for natural gas liquids have increased compared to first quarter 2020 levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream. For the remainder of 2021 we project our natural gas net sales prices will be a discount to Henry Hub benchmark prices of between zero and $0.50 per Mcf.

Derivatives. Changes in market prices during the first quarter of 2021 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $43.5 million for the period, representing $29.4 million of cash losses and $14.1 million of unsettled non-cash losses. We had no outstanding derivative instruments during the first quarter of 2020.

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, which are impacted by our production volumes and the timing and extent of our drilling and completion projects. Revenues associated with such activities decreased $6.3 million, or 35%, from $18.1 million for the first quarter of 2020 to $11.8 million for the first quarter of 2021 due to reduced water handling activities resulting from a decrease in production and reduced completion activities compared to the 2020 first quarter. The decreased activities also resulted in a reduction in service-related expenses compared to the prior period.

Operating Costs and Expenses

Production Expenses. Production expenses decreased $25.4 million, or 21%, from $118.5 million for the first quarter of 2020 to $93.1 million for the first quarter of 2021. This decrease resulted from reduced service costs being incurred in conjunction with lower sales volumes, cost control efforts, operating efficiency gains, and a higher portion of our production coming from wells in Oklahoma which typically have lower operating costs compared to wells in the Bakken, all of which led to a decrease in our production expenses on a per-Boe basis to $3.35 per Boe for the 2021 first quarter compared to $3.61 per Boe for the 2020 first quarter.

Production Taxes. Production taxes increased $12.8 million, or 18%, to $84.0 million for the first quarter of 2021 compared to $71.2 million for the first quarter of 2020 due to a 45% increase in crude oil and natural gas sales partially offset by a decrease in our average production tax rate. Our production taxes as a percentage of net crude oil and natural gas sales decreased from 8.9% for the first quarter of 2020 to 7.0% for the first quarter of 2021 primarily resulting from an increase in the proportion of our revenues being generated in Oklahoma in the current period, which has lower production tax rates compared to North Dakota.

Depreciation, Depletion, Amortization and Accretion. Total DD&A decreased $27.1 million, or 5%, to $509.6 million for the first quarter of 2021 compared to $536.7 million for the first quarter of 2020 primarily due to a 15% decrease in total sales volumes, the impact of which was partially offset by an increase in our DD&A rate per Boe as further discussed below. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

$/Boe	Three months ended March 31,	
	2021	2020
Crude oil and natural gas	$ 18.03	$ 16.12
Other equipment	0.22	0.16
Asset retirement obligation accretion	0.10	0.07
Depreciation, depletion, amortization and accretion	$ 18.35	$ 16.35

Estimated proved reserves are a key component in our computation of DD&A expense. Proved reserves are determined using the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months as required by SEC rules. Holding all other factors constant, if proved reserves are revised downward due to commodity price declines or other reasons, 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.

Downward revisions of proved reserves at year-end 2020 prompted by a significant decrease in average commodity prices and other factors resulted in an increase in our DD&A rate for crude oil and natural gas properties in the first quarter of 2021 compared to the first quarter of 2020.

NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices in 2021 have been higher than average prices for the full year of 2020. If commodity prices remain at current levels for an extended period, upward price-related revisions of proved reserves may occur in the future, which may be significant and could result in a decrease in our DD&A rate relative to the 2021 first quarter. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments decreased $211.1 million to $11.4 million for the first quarter of 2021 compared to $222.5 million for the first quarter of 2020, primarily reflecting lower proved property impairments in the current period. No proved property impairments were recognized in the 2021 first quarter as estimated future net cash flows were determined to be in excess of cost basis due to improved commodity prices, while proved property impairments totaled $205.5 million in the 2020 first quarter. Additionally, impairments of unproved properties decreased $5.5 million in the 2021 first quarter compared to the 2020 first quarter, reflecting changes in management's estimates of unproved properties not expected to be transferred to proved properties over the lives of the leases.

General and Administrative Expenses. Total G&A expenses increased $9.9 million, or 23%, to $52.8 million for the first quarter of 2021 compared to $42.9 million for the first quarter of 2020.

Total G&A expenses include non-cash charges for equity compensation of $16.9 million for the first quarter of 2021, consistent with $16.4 million for the first quarter of 2020. G&A expenses other than equity compensation totaled $35.9 million for the 2021 first quarter, an increase of $9.4 million, or 35%, compared to $26.5 million for the 2020 first quarter. This increase was primarily due to an increase in employee benefits coupled with lower overhead recoveries from joint interest owners driven by reduced drilling, completion, and production activities compared to the 2020 first quarter.

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

$/Boe	Three months ended March 31,	
	2021	2020
General and administrative expenses	$ 1.29	$ 0.81
Non-cash equity compensation	0.61	0.50
Total general and administrative expenses	$ 1.90	$ 1.31

Interest Expense. Interest expense totaled $65.0 million for the first quarter of 2021, consistent with $63.6 million for the first quarter of 2020. We reduced our outstanding debt by $560 million during the 2021 first quarter and expect our interest expense for the remaining quarterly periods of 2021 to be lower than the first quarter amount. The 2021 first quarter includes $3.2 million of interest expense associated with our 2022 Notes that were redeemed as discussed in *Note 7. Long-Term Debt* and *Note 13. Subsequent Events* in *Notes to Unaudited Condensed Consolidated Financial Statements.*

Income Taxes. For the first quarters of 2021 and 2020 we provided for income taxes at a combined federal and state tax rate of 24.5% of our pre-tax income/loss. We recorded an income tax provision of $80.5 million for the 2021 first quarter and an income tax benefit of $52.2 million for the 2020 first quarter, which resulted in effective tax rates of 23.6% and 21.9%, respectively, after taking into account statutory tax rates, permanent taxable differences, tax effects from equity compensation, changes in valuation allowances, and other items. 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 rates.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt securities. Additionally, asset dispositions and joint development arrangements have provided a source of cash flow for use in reducing debt and enhancing liquidity. In light of the challenges facing our business and industry, we remain committed to operating in a responsible manner to preserve financial flexibility, liquidity, and the strength of our balance sheet. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from potential sales of assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

At March 31, 2021, we had $1.5 billion of borrowing availability under our credit facility. Our credit facility, which is unsecured and has no borrowing base subject to redetermination, does not mature until April 2023. In April 2021, we redeemed the remaining $230.8 million principal amount of our outstanding 2022 Notes. After this redemption, we have no near-term senior note maturities, with our earliest scheduled maturity being our $649.6 million of 2023 Notes due in April 2023.

Based on our planned capital spending, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility and senior note indentures. Further, based on current market indications, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of March 31, 2021, 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 if needed to preserve liquidity and financial flexibility to fund our operations.

Cash Flows

Cash flows from operating activities

Net cash provided by operating activities increased $376 million, or 57%, to $1.04 billion for the first quarter of 2021 compared to $664 million for the first quarter of 2020 primarily due to a $385 million increase in crude oil and natural gas revenues due to the previously described increases in commodity prices in the current period. This increase was partially offset by a $29 million increase in realized cash losses on matured commodity derivatives in the 2021 first quarter compared to the 2020 first quarter.

Based on current market indications, we expect our operating cash flows for the remainder of 2021 will continue to be higher than 2020 levels, as our 2020 results were significantly impacted by the economic effects from the COVID-19 pandemic on crude oil demand and prices which led to material reductions in our production, revenues, and operating cash flows in 2020.

Cash flows from investing activities

Net cash used in investing activities decreased $279 million, or 39%, to $428 million for the first quarter of 2021 compared to $707 million for the first quarter of 2020, reflecting our focus on maintaining capital spending discipline to maximize cash flow generation for debt reduction. Our cash flows used in investing activities for the 2021 first quarter include $185.1 million paid in March 2021 to acquire properties in the Powder River Basin of Wyoming as discussed in *Notes to Unaudited Condensed Consolidated Financial Statements–Note 12. Property Acquisition*. Our non-acquisition capital expenditures for full year 2021 are budgeted to be $1.4 billion compared to $1.2 billion of non-acquisition capital spending for full year 2020.

Cash flows from financing activities

Net cash used in financing activities for the first quarter of 2021 totaled $564 million, primarily consisting of $400 million of cash used to redeem a portion of our 2022 Notes in January 2021 and $160 million of net repayments on our credit facility. We intend to continue reducing our long-term debt in 2021 and beyond.

Net cash provided by financing activities for the first quarter of 2020 totaled $521 million, driven by $680 million of net borrowings incurred on our credit facility to increase cash on hand during 2020 due to economic uncertainties from the COVID-19 pandemic, which was partially offset by $127 million of cash used to repurchase shares of our common stock, $19 million of cash dividends paid on common stock, and $23 million of cash used to repurchase senior notes in open market transactions.

Future Sources of Financing

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

Based on current market indications, our 2021 capital spending plan is expected to be funded from operating cash flows. Any cash flow deficiencies are expected to be funded by borrowings under our credit facility. If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our credit facility if needed to fund our operations and business plans. We may choose to access banking or capital markets for additional financing or capital to fund our operations or take advantage of business opportunities that may arise. Further, we may sell assets or enter into strategic joint development opportunities in order to obtain funding if such transactions can be executed on satisfactory terms. However, no assurance can be given that such transactions will occur.

Credit facility

We have an unsecured credit facility, maturing in April 2023, with aggregate lender commitments totaling $1.5 billion. The commitments are from a syndicate of 14 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of March 31, 2021, we had no outstanding borrowings on our credit facility.

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

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

We were in compliance with our credit facility covenants at March 31, 2021 and expect to maintain such compliance. At March 31, 2021, our consolidated net debt to total capitalization ratio was 0.39 to 1.00. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing if needed to support our business. At March 31, 2021, our total debt would have needed to independently increase by approximately $9.5 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 $5.1 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at March 31, 2021 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.

Future Capital Requirements

Senior notes

In April 2021, we redeemed the remaining $230.8 million principal amount of our outstanding 2022 Notes using proceeds from lower-rate credit facility borrowings. Our outstanding senior note obligations now total $4.76 billion as of April 28, 2021. We have no near-term senior note maturities, with our earliest scheduled maturity being our $649.6 million of 2023 Notes due in April 2023. 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, 2021 and expect to maintain such compliance. 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 do not trigger additional senior note covenants.

Mineral acquisition relationship

In October 2018, Continental entered into a strategic relationship with Franco-Nevada Corporation to acquire oil and gas mineral interests within an area of mutual interest through a minerals subsidiary named The Mineral Resources Company II, LLC ("TMRC II"). Under the relationship, the parties have agreed to spend up to a remaining aggregate total of $139 million to acquire mineral interests. Continental agreed to fund 20% of future mineral acquisitions and will be entitled to receive between 25% and 50% of total revenues generated by TMRC II based upon performance relative to predetermined production targets, while Franco-Nevada will fund 80% of future acquisitions and will be entitled to receive between 50% and 75% of TMRC II's revenues. Based upon production targets achieved to date, Continental is currently earning 50% of TMRC II's revenues and such allocation is expected to continue through at least year-end 2021.

Capital expenditures

We remain committed to operating in a disciplined, capital-efficient manner to maximize cash flow generation. Our capital expenditures budget for 2021 is $1.4 billion, which is expected to be allocated as reflected in the table below. Based on current expectations of commodity prices and costs, our 2021 capital budget is expected to be funded from operating cash flows. Acquisition expenditures are not budgeted, with the exception of planned levels of spending for mineral acquisitions made in conjunction with our relationship with Franco-Nevada.

In millions		**2021 Budget**
Exploration and development	$	1,112
Land costs		85
Mineral acquisitions attributable to Continental (1)		13
Capital facilities, workovers, water infrastructure, and other corporate assets		186
Seismic		4
2021 capital budget attributable to Continental	$	1,400
Mineral acquisitions attributable to Franco-Nevada (1)		52
Total 2021 capital budget (2)	$	1,452

(1) Represents planned spending for mineral acquisitions by TMRC II under our relationship with Franco-Nevada. Continental holds a controlling financial interest in TMRC II and therefore consolidates the financial results and capital expenditures of the entity. With a carry structure in place, Continental will fund 20% of 2021 planned spending, or $13 million, and Franco-Nevada will fund the remaining 80%, or $52 million.

(2) Excludes our March 2021 acquisition of properties in the Powder River Basin of Wyoming discussed in *Notes to Unaudited Condensed Consolidated Financial Statements–Note 12. Property Acquisition.*

For the three months ended March 31, 2021, we invested $293.4 million in our capital program excluding $207.6 million of unbudgeted acquisitions and including $49.4 million of capital costs associated with increased accruals for capital expenditures as compared to December 31, 2020. Our 2021 year to date capital expenditures were allocated as shown in the table below.

In millions		**1Q 2021**
Exploration and development drilling	$	255.6
Land costs		7.5
Mineral acquisitions attributable to Continental		0.2
Capital facilities, workovers, water infrastructure, and other corporate assets		27.4
Seismic		2.7
Capital expenditures attributable to Continental, excluding unbudgeted acquisitions		293.4
Acquisitions of producing properties		183.3
Acquisitions of non-producing properties		24.3
Total unbudgeted acquisitions		207.6
Total capital expenditures attributable to Continental	$	501.0
Mineral acquisitions attributable to Franco-Nevada		0.9
Total capital expenditures	$	501.9

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

Commitments and contingencies

Refer to *Note 8. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements* for discussion of certain future commitments of the Company. Based on current market indications, we expect to meet in the ordinary course of business our contractual cash commitments to third parties as of March 31, 2021.

On July 6, 2020, the U.S. District Court for the District of Columbia ruled that the U.S. Army Corps of Engineers ("Corps"), which had previously issued an easement near the Standing Rock Sioux tribal lands allowing the Dakota Access Pipeline ("DAPL") to cross a water body, had failed to adequately consider the environmental impacts under the National Environmental Protection Act ("NEPA") arising out of such pipeline crossing this water body, and directed the Corps to prepare a new environmental impact statement ("EIS") as well as ordering the owners of DAPL to shut down the pipeline pending completion of the EIS. The DAPL is owned and operated by a third party and carries Bakken-produced crude oil from North Dakota to Illinois. The pipeline owner sought an emergency stay of the shut-down order from the U.S. Court of Appeals for the District of Columbia Circuit (the "Appeals Court"). On July 14, 2020, the Appeals Court issued a temporary stay, followed by an August 5, 2020 administrative stay of such order, which has allowed the pipeline to continue operating. On January 26, 2021, the Appeals Court affirmed that part of the lower court decision vacating the Corps' easement while it prepares a new EIS, but reversed the lower court's order to shut down the pipeline because the lower court had not properly evaluated such action under an applicable NEPA factoring test established under case law. On April 23, 2021, the Appeals Court denied the pipeline owner's request for rehearing. The Corps is currently conducting the court-ordered environmental review. Once this review is finished, which completion is anticipated by no later than early 2022, the Corps will determine whether the pipeline is safe to operate or must be permanently shut down. On April 9, 2021, the Biden Administration announced that the Corps will not take immediate action to shut down the DAPL while it conducts the environmental review. U.S. District Judge James Boasberg, who is set to rule on the Standing Rock Sioux Tribe's request for an injunction shutting down the DAPL while the environmental review is being conducted, granted a 10-day continuance following the Biden Administration's announcement on April 9, 2021 and may render a decision as early as May 2021.

The Company utilizes DAPL to transport a portion of its North region crude oil production to ultimate markets on the U.S. gulf coast. Currently, the Company is committed to transport 3,550 barrels per day on the pipeline through February 2026 and has an additional commitment to transport an incremental 26,450 barrels per day for 7 years effective upon the pending completion of a DAPL expansion project which is estimated to occur in the second half of 2021. If transportation capacity on DAPL becomes restricted or unavailable, we have the ability to utilize other third party pipelines or rail facilities to transport our Bakken crude oil production to market, although such alternatives may be more costly. A restriction of DAPL's takeaway capacity may have an impact on prices for Bakken-produced barrels and result in wider differentials relative to WTI benchmark prices in the future, the amount of which is uncertain.

Dividend declaration

On April 27, 2021, the Company's Board of Directors approved the reinstatement of a quarterly dividend of $0.11 per share on the Company's outstanding common stock, payable on May 24, 2021 to shareholders of record as of May 10, 2021.

Senior note redemptions

As discussed in *Note 7. Long-Term Debt* and *Note 13. Subsequent Events* in *Notes to Unaudited Condensed Consolidated Financial Statements*, in January 2021 and April 2021 we redeemed the remaining principal amount of our outstanding 2022 Notes. From time to time, we may seek to execute additional redemptions or repurchases of our senior notes for cash in open market transactions, privately negotiated transactions, or otherwise. Such redemptions or repurchases will depend on prevailing market conditions, our liquidity and prospects for future access to capital, and other factors. The amounts involved in any such transactions, individually or in the aggregate, may be material.

Off-balance sheet arrangements

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

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our 2020 Form 10-K.

New Accounting Pronouncements

See *Note 2. Basis of Presentation and Significant Accounting Policies* in *Notes to Unaudited Condensed Consolidated Financial Statements* for a discussion of the new income tax accounting standard adopted on January 1, 2021, which did not have a material impact on our financial position, results of operations, or cash flows.

Legislative and Regulatory Developments

The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. In January 2021 President Biden issued executive orders that, among other things, establish new greenhouse gas emission standards for the oil and gas sector. President Biden may continue to issue additional executive orders in pursuit of his regulatory agenda and, with control of Congress shifting in January 2021, there is the potential for the revision of existing laws and regulations or the adoption of new legislation that could adversely affect the oil and gas industry. See *Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry* in our Form 10-K for the year ended December 31, 2020 for a discussion of significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.

Non-GAAP Financial Measures

Net crude oil and natural gas sales and net sales prices

Revenues and transportation expenses associated with production from our operated properties are reported separately as discussed in *Notes to Unaudited Condensed Consolidated Financial Statements–Note 4. Revenues*. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received. As a result, the separate presentation of revenues and transportation expenses from our operated properties differs from the net presentation from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results and to achieve comparability between operated and non-operated revenues, we have presented crude oil and natural gas sales net of transportation expenses in *Management's Discussion and Analysis of Financial Condition and Results of Operations*, which we refer to as "net crude oil and natural gas sales," a non-GAAP measure. Average sales prices calculated using net crude oil and natural gas sales are referred to as "net sales prices," a non-GAAP measure, and are calculated by taking revenues less transportation expenses divided by sales volumes, whether for crude oil or natural gas, as applicable. Management believes presenting our revenues and sales prices net of transportation expenses is useful because it normalizes the presentation differences between operated and non-operated revenues and allows for a useful comparison of net realized prices to NYMEX benchmark prices on a Company-wide basis.

The following table presents a reconciliation of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the three months ended March 31, 2021 and 2020.

	Three months ended March 31, 2021			Three months ended March 31, 2020		
In thousands	**Crude oil**	**Natural gas**	**Total**	**Crude oil**	**Natural gas**	**Total**
Crude oil and natural gas sales (GAAP)	$ 768,768	$ 478,765	$ 1,247,533	$ 773,770	$ 88,973	$ 862,743
Less: Transportation expenses	(40,079)	(10,177)	(50,256)	(50,372)	(10,130)	(60,502)
Net crude oil and natural gas sales (non-GAAP)	$ 728,689	$ 468,588	$ 1,197,277	$ 723,398	$ 78,843	$ 802,241
Sales volumes (MBbl/MMcf/MBoe)	13,726	84,289	27,774	18,251	87,453	32,826
Net sales price (non-GAAP)	$ 53.09	$ 5.56	$ 43.11	$ 39.64	$ 0.90	$ 24.44

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 crude oil and natural gas. 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 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, 2021, and excluding the effect of derivative instruments in place, our annual revenue would increase or decrease by approximately $554 million for each $10.00 per barrel change in crude oil prices at March 31, 2021 and $342 million for each $1.00 per Mcf change in natural gas prices at March 31, 2021.

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.

The fair value of our derivative instruments at March 31, 2021 was a net liability of $0.6 million, which is comprised of a $10.3 million net liability associated with our crude oil derivatives nearly offset by a $9.7 million net asset associated with our natural gas derivatives. The following table shows how a hypothetical +/- 10% change in the underlying forward prices used to calculate the fair value of our derivatives would impact the fair value estimates as of March 31, 2021.

In thousands	**Change in Forward Price**	**Hypothetical Fair Value Asset (Liability)**
Crude Oil	-10%	$4,889
Crude Oil	+10%	($26,418)
Natural Gas	-10%	$24,298
Natural Gas	+10%	($3,891)

Changes in the fair value of our 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 ($691 million in receivables at March 31, 2021), and our joint interest and other receivables ($171 million at March 31, 2021).

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; however, we could experience increased exposure to credit losses in the future, which may be material, if the adverse economic effects of the COVID-19 pandemic persist for an extended period.

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 $24 million at March 31, 2021, 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 net production proceeds against amounts owed in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial; however, we could experience increased exposure to credit losses in the future, which may be material, if the adverse economic effects of the COVID-19 pandemic persist for an extended period.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to variable-rate borrowings we may have outstanding from time to time under our credit facility. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates.

We had no outstanding borrowings on our credit facility at March 31, 2021.

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, 2021 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, 2021, 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

We are involved in various legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, we do not expect them to have a material effect on our financial condition, results of operations or cash flows.

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 2020 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 2020 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 2020 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 table below provides information about purchases of shares of our common stock during the three months ended March 31, 2021.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (1)	Maximum dollar value of shares that may yet be purchased under the plans or programs (in millions) (1)
January 1, 2021 to January 31, 2021:				
Repurchases for tax withholdings (2)	15,189	$ 19.19	—	—
February 1, 2021 to February 28, 2021:				
Repurchases for tax withholdings (2)	374,313	$ 23.02	—	—
March 1, 2021 to March 31, 2021:				
Repurchases for tax withholdings (2)	983	$ 29.29	—	—
Total for the quarter	390,485	$ 22.89	—	—

(1) In May 2019 our Board of Directors approved the initiation of a share repurchase program to acquire up to $1 billion of our common stock beginning in June 2019 at times and levels deemed appropriate by management. The program was announced on June 3, 2019 and does not have a set expiration date. The share repurchase program may be modified, suspended, or terminated by our Board of Directors at any time. No share repurchases were made by the Company under the program during the three months ended March 31, 2021. The dollar value of shares that may yet be purchased under the program totaled $682.9 million as of March 31, 2021.

(2) Amounts represent shares surrendered by employees to cover tax liabilities in connection with the vesting of restricted stock granted under the Company's 2013 Long-Term Incentive Plan. We paid the associated taxes to the applicable taxing authorities. The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

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 amendments filed on June 15, 2015 and May 21, 2020 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2020 (Commission File No. 001-32886) filed August 3, 2020 and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company’s Form 10-K for the year ended December 31, 2017 (Commission File No. 001-32886) filed February 21, 2018 and incorporated herein by reference.
10.1*†	Description of cash bonus plan as of March 16, 2021.
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*	Inline XBRL Instance Document - the Inline XBRL Instance Document does not appear in the Interactive Data file because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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

SIGNATURE

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

CONTINENTAL RESOURCES, INC.

Date:	April 28, 2021	By:	/s/ John D. Hart
			John D. Hart Sr. Vice President, Chief Financial Officer and Chief Strategy Officer (Duly Authorized Officer and Principal Financial Officer)

Exhibit 10.1

Description of Cash Bonus Plan
Updated as of March 16, 2021

On February 22, 2013, the Compensation Committee (the "Compensation Committee") of the Board of Directors (the "Board") of Continental Resources, Inc. (the "Company") approved a cash bonus plan (the "CLR Bonus Plan") that applies to the employees of the Company, including the Company's executive officers. On March 16, 2021, the Compensation Committee approved a change to the factors used to set the size of the annual bonus pool from the factors used to set the annual bonus pool in prior years. The CLR Bonus Plan is designed to reward the Company's employees for achieving annual performance and strategic goals. The CLR Bonus Plan provides for the annual payment of cash bonuses, subject to the discretion of the Compensation Committee, which has the ability to exercise complete discretion in administering the CLR Bonus Plan. On August 3, 2018, the Board approved a clawback policy pursuant to which awards to executive officers under the CLR Bonus Plan may be recovered if there is a financial restatement impacting a metric relevant to an award and certain other conditions described in the policy are satisfied. The policy only applies to awards made after August 3, 2018.

Under the CLR Bonus Plan, the bonus pool will be budgeted based on the aggregate target bonus amount of all employees participating in the CLR Bonus Plan (referred to herein as the "Target Pool Size"). The size of the bonus pool will be initially set within a range based on the following factors (the "Bonus Pool Factors"): net cash provided by operating activities (weighted at 25%); return on capital employed (weighted at 25%); resource replacement ratio (weighted at 20%); health safety and environmental performance (weighted at 10%); production growth (weighted at 10%); and proved developed finding and development cost per barrel of oil equivalent ("Boe") (weighted at 10%). The Bonus Pool Factors will remain in effect until changed by the Compensation Committee.

The Compensation Committee has complete discretion to increase, decrease or leave the size of the bonus pool unchanged. In making the determination whether to adjust the size of the bonus pool, the Compensation Committee will consider such additional matters as it deems relevant from time to time, including, without limitation, the Company's performance against key strategic and other initiatives identified by the Compensation Committee in areas such as production costs and cycle times, maintenance of financial and other ratios, budget compliance and business process improvements. The size of the bonus pool as determined by the Compensation Committee is referred to herein as the "Final Pool Size." The ratio of the Target Pool Size to the Final Pool Size will be used to determine the Company multiplier in the calculation of an individual's bonus amount under the CLR Bonus Plan.

Individual awards for participants in the CLR Bonus Plan, including the Company's executive officers, will be calculated utilizing the following formula:

Base Earnings x Target Bonus x Company Multiplier x Individual Multiplier = Initial Bonus Amount

The target annual cash bonus amounts for the Company's executive officers under the CLR Bonus Plan will be determined by the Compensation Committee, with appropriate input from our Executive Chairman and Chief Executive Officer. In the case of Mr. Harold Hamm, the Company's Executive Chairman, and Mr. William Berry, the Company's Chief Executive Officer, the Compensation Committee may also present recommended target bonus amounts to the Board, which also has the discretion to increase or decrease the recommended target bonus amounts as presented by the Compensation Committee.

Except for Mr. Hamm and Mr. Berry, the individual multiplier for bonuses will be based on the subjective evaluation of each of the Company's executive officer's supervisor or supervisors. Mr. Hamm's and Mr. Berry's individual multiplier will be determined based on the subjective evaluation of the Compensation Committee.

Once the executive officers' Initial Bonus Amounts are calculated, they will be presented to the Compensation Committee for review, and in the case of Mr. Hamm and Mr. Berry, if the Compensation Committee so determines (as reflected in its committee charter), also be presented to the Board, both of which retain the discretion to increase or decrease individual Initial Bonus Amounts and determine final awards.

Exhibit 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)

I, William B. Berry, certify that:

1. I have reviewed this report on Form 10-Q for the period ended March 31, 2021 of Continental Resources, Inc. ("Registrant");

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

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

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

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

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

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

   (d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: April 28, 2021

/s/ William B. Berry

William B. Berry
Chief Executive Officer

Exhibit 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)

I, John D. Hart, certify that:

1. I have reviewed this report on Form 10-Q for the period ended March 31, 2021 of Continental Resources, Inc. ("Registrant");

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

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

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

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

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

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

   (d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: April 28, 2021

/s/ John D. Hart

John D. Hart
Sr. Vice President, Chief Financial Officer and Chief Strategy Officer

Exhibit 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)

Pursuant to 18 U.S.C. Section 1350, the undersigned officers of Continental Resources, Inc. (the "Company") hereby certify that the Company's Report on Form 10-Q for the quarterly period ended March 31, 2021 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William B. Berry	/s/ John D. Hart
William B. Berry	**John D. Hart**
Chief Executive Officer	**Sr. Vice President, Chief Financial Officer and Chief Strategy Officer**
April 28, 2021	**April 28, 2021**