UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2019

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-37697

CENTENNIAL RESOURCE DEVELOPMENT, INC.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**47-5381253**
(State of Incorporation)	(I.R.S. Employer Identification Number)
1001 Seventeenth Street, Suite 1800, Denver, Colorado	**80202**
(Address of Principal Executive Offices)	(Zip Code)

(720) 499-1400

(Registrant's Telephone Number, Including Area Code)

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

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

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 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 No

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

Large accelerated filer	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

As of October 31, 2019, there were 275,600,503 shares of Class A Common Stock, par value $0.0001 per share and 1,143,039 shares of Class C Common Stock, par value $0.0001 per share, outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Bbl/d. One Bbl per day.

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

Boe/d. One Boe per day.

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

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

Development project. The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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

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

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

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

LIBOR. London Interbank Offered Rate.

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

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

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

NYMEX. The New York Mercantile Exchange.

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

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

Proved undeveloped reserves or PUD. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion or recompletion.

Realized price. The cash market price less differentials.

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

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project.

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

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

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

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

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

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

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

GLOSSARY OF CERTAIN OTHER TERMS

The following are definitions of certain other terms that are used in this Quarterly Report on Form 10-Q:

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

Celero. Celero Energy Company, LP, a Delaware limited partnership.

Centennial Contributors. CRD, NGP Follow-On and Celero, collectively.

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

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

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

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

CRD. Centennial Resource Development, LLC, a Delaware limited liability company, which was dissolved on June 15, 2018.

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

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

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

NGP Follow-On. NGP Centennial Follow-On LLC, a Delaware limited liability company.

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

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Quarterly Report") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Quarterly Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "goal," "plan," "target" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2018 (the "2018 Annual Report") and the risk factors and other cautionary statements contained in our other filings with the United States Securities and Exchange Commission ("SEC").

Forward-looking statements may include statements about:

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

You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including but not limited to those risks described under "Item 1A. Risk Factors" in our 2018 Annual Report. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

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

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements.

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

All forward-looking statements, expressed or implied, are made only as of the date of this Quarterly Report. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this Quarterly Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 10,933	$ 18,157
Accounts receivable, net	141,312	100,623
Derivative instruments	—	1,632
Prepaid and other current assets	8,931	9,777
Total current assets	161,176	130,189
Property and Equipment		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,515,458	1,680,065
Proved properties	3,704,555	2,895,280
Accumulated depreciation, depletion and amortization	(809,979)	(496,900)
Total oil and natural gas properties, net	4,410,034	4,078,445
Other property and equipment, net	14,799	8,837
Total property and equipment, net	4,424,833	4,087,282
Noncurrent assets		
Operating lease right-of-use assets	17,182	—
Other noncurrent assets	42,940	42,550
TOTAL ASSETS	$ 4,646,131	$ 4,260,021
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 267,962	$ 240,575
Derivative instruments	4,433	6,051
Operating lease liabilities	14,151	—
Other current liabilities	942	1,090
Total current liabilities	287,488	247,716
Noncurrent liabilities		
Long-term debt, net	1,001,867	691,630
Asset retirement obligations	14,629	13,895
Deferred income taxes	84,471	62,167
Operating lease liabilities	3,862	—
Other long-term liabilities	—	744
Total liabilities	1,392,317	1,016,152
Commitments and contingencies (Note 11)		
Shareholders’ equity		
Preferred stock, $0.0001 par value, 1,000,000 shares authorized:		
Series A: 1 share issued and outstanding	—	—
Common stock, $0.0001 par value, 620,000,000 shares authorized:		
Class A: 280,443,894 shares issued and 275,556,804 shares outstanding at September 30, 2019 and 265,859,273 shares issued and 264,323,328 shares outstanding at December 31, 2018	28	27
Class C (Convertible): 1,143,039 shares issued and outstanding at September 30, 2019 and 12,003,183 shares issued and outstanding at December 31, 2018	—	1
Additional paid-in capital	2,967,149	2,833,611
Retained earnings	272,718	266,538
Total shareholders’ equity	3,239,895	3,100,177
Noncontrolling interest	13,919	143,692
Total equity	3,253,814	3,243,869
TOTAL LIABILITIES AND EQUITY	$ 4,646,131	$ 4,260,021

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Operating revenues				
Oil and gas sales	$ 229,130	$ 234,880	$ 687,938	$ 668,541
Operating expenses				
Lease operating expenses	42,330	23,706	107,077	59,164
Severance and ad valorem taxes	12,213	14,410	45,519	42,791
Gathering, processing and transportation expenses	20,853	16,090	52,120	45,214
Depreciation, depletion and amortization	112,720	83,423	321,392	224,379
Impairment and abandonment expense	6,745	8,612	42,427	10,396
Exploration expense	2,869	2,712	9,246	8,026
General and administrative expenses	20,036	16,561	56,589	44,667
Total operating expenses	217,766	165,514	634,370	434,637
Net gain (loss) on sale of long-lived assets	(22)	52	(15)	(74)
Income from operations	11,342	69,418	53,553	233,830
Other income (expense)				
Interest expense	(15,246)	(6,534)	(39,843)	(18,138)
Net gain (loss) on derivative instruments	1,522	(9,571)	(2,221)	14,969
Other income (expense)	62	13	321	(4)
Total other income (expense)	(13,662)	(16,092)	(41,743)	(3,173)
Income (loss) before income taxes	(2,320)	53,326	11,810	230,657
Income tax expense	(1,393)	(11,652)	(5,058)	(50,729)
Net income (loss)	(3,713)	41,674	6,752	179,928
Less: Net income (loss) attributable to noncontrolling interest	(128)	2,386	572	11,009
Net income (loss) attributable to Class A Common Stock	$ (3,585)	$ 39,288	$ 6,180	$ 168,919
Income (loss) per share of Class A Common Stock:				
Basic	$ (0.01)	$ 0.15	$ 0.02	$ 0.64
Diluted	$ (0.01)	$ 0.15	$ 0.02	$ 0.63

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

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

	For the Nine Months Ended September 30,	
	2019	2018
Cash flows from operating activities:		
Net income	$ 6,752	$ 179,928
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	321,392	224,379
Stock-based compensation expense	21,351	14,329
Impairment and abandonment expense	42,427	10,396
Exploratory dry hole costs	—	395
Deferred tax expense	5,058	50,729
Net loss on sale of long-lived assets	15	74
Non-cash portion of derivative (gain) loss	14	(579)
Amortization of debt issuance costs and discount	2,070	1,258
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(47,771)	(18,327)
(Increase) decrease in prepaid and other assets	(995)	(52)
Increase (decrease) in accounts payable and other liabilities	34,562	32,165
Net cash provided by operating activities	384,875	494,695
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(73,346)	(114,870)
Drilling and development capital expenditures	(644,945)	(723,100)
Purchases of other property and equipment	(8,207)	(4,409)
Proceeds from sales of oil and natural gas properties	28,378	147,413
Net cash used in investing activities	(698,120)	(694,966)
Cash flows from financing activities:		
Proceeds from borrowings under revolving credit facility	345,000	295,000
Repayment of borrowings under revolving credit facility	(525,000)	(155,000)
Proceeds from issuance of 2027 Senior Notes	496,175	—
Debt issuance costs	(7,200)	(4,217)
Proceeds from exercise of stock options	—	847
Restricted stock used for tax withholdings	(911)	(1,119)
Net cash provided by financing activities	308,064	135,511
Net decrease in cash, cash equivalents and restricted cash	(5,181)	(64,760)
Cash, cash equivalents and restricted cash, beginning of period	21,422	125,915
Cash, cash equivalents and restricted cash, end of period	$ 16,241	$ 61,155

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

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

	For the Nine Months Ended September 30,	
	2019	2018
Supplemental cash flow information		
Cash paid for interest	$ 27,985	$ 15,587
Operating lease liability payments:		
Cash used in operating activities	16,808	—
Cash used in investing activities	13,946	—
Supplemental non-cash activity		
Accrued capital expenditures included in accounts payable and accrued expenses	$ 120,238	$ 97,844
Asset retirement obligations incurred, including revisions to estimates	1,075	1,040
Right-of-use assets obtained in exchange for operating lease liabilities	35,686	—

Reconciliation of cash, cash equivalents and restricted cash presented on the Consolidated Statements of Cash Flows for the periods presented:

	For the Nine Months Ended September 30,	
	2019	2018
Cash and cash equivalents	$ 10,933	$ 58,922
Restricted cash[(1)]	5,308	2,233
Total cash, cash equivalents and restricted cash	$ 16,241	$ 61,155

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

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS’ EQUITY (unaudited)
(in thousands)

	Common Stock				**Preferred Stock**						
	Class A		Class C		Series A		Additional Paid-In Capital	Retained Earnings	Total Shareholder's Equity	Non-controlling Interest	Total Equity
	Shares	Amount	Shares	Amount	Shares	Amount					
Balance at December 31, 2018	265,859	$ 27	12,003	$ 1	—	$ —	$2,833,611	$ 266,538	$ 3,100,177	$ 143,692	$3,243,869
Restricted stock issued	436	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(24)	—	—	—	—	—	(291)	—	(291)	—	(291)
Stock-based compensation	—	—	—	—	—	—	6,483	—	6,483	—	6,483
Net income (loss)	—	—	—	—	—	—	—	(8,112)	(8,112)	(425)	(8,537)
Balance at March 31, 2019	266,271	$ 27	12,003	$ 1	—	$ —	$2,839,803	$ 258,426	$ 3,098,257	$ 143,267	$3,241,524
Restricted stock issued	4	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(16)	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(4)	—	—	—	—	—	(41)	—	(41)	—	(41)
Stock-based compensation	—	—	—	—	—	—	6,758	—	6,758	—	6,758
Net income (loss)	—	—	—	—	—	—	—	17,877	17,877	1,125	19,002
Balance at June 30, 2019	266,255	$ 27	12,003	$ 1	—	$ —	$2,846,520	$ 276,303	$ 3,122,851	$ 144,392	$3,267,243
Restricted stock issued	3,466	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(30)	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(107)	—	—	—	—	—	(579)	—	(579)	—	(579)
Stock-based compensation	—	—	—	—	—	—	8,110	—	8,110	—	8,110
Conversion of common stock from Class C to Class A, net of tax	10,860	1	(10,860)	(1)	—	—	113,098	—	113,098	(130,345)	(17,247)
Net income (loss)	—	—	—	—	—	—	—	(3,585)	(3,585)	(128)	(3,713)
Balance at September 30, 2019	280,444	$ 28	1,143	$ —	—	$ —	$2,967,149	$ 272,718	$ 3,239,895	$ 13,919	$3,253,814

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

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

	Common Stock				Preferred Stock						
	Class A		Class C		Series A		Additional Paid-In Capital	Retained Earnings	Total Shareholder's Equity	Non-controlling Interest	Total Equity
	Shares	Amount	Shares	Amount	Shares	Amount					
Balance at December 31, 2017	261,338	$ 26	15,661	$ 2	—	$ —	$2,767,558	$ 66,639	$ 2,834,225	$ 169,747	$3,003,972
Restricted stock issued	199	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(26)	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(10)	—	—	—	—	—	(192)	—	(192)	—	(192)
Stock option exercises	10	—	—	—	—	—	164	—	164	—	164
Stock-based compensation	—	—	—	—	—	—	4,333	—	4,333	—	4,333
Conversion of common stock from Class C to Class A, net of tax	3,347	1	(3,347)	(1)	—	—	42,188	—	42,188	(35,519)	6,669
Net income (loss)	—	—	—	—	—	—	—	66,090	66,090	4,682	70,772
Balance at March 31, 2018	264,858	$ 27	12,314	$ 1	—	$ —	$2,814,051	$ 132,729	$ 2,946,808	$ 138,910	$3,085,718
Restricted stock issued	23	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(17)	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(4)	—	—	—	—	—	(65)	—	(65)	—	(65)
Stock option exercises	28	—	—	—	—	—	411	—	411	—	411
Stock-based compensation	—	—	—	—	—	—	4,655	—	4,655	—	4,655
Net income (loss)	—	—	—	—	—	—	—	63,541	63,541	3,941	67,482
Balance at June 30, 2018	264,888	$ 27	12,314	$ 1	—	$ —	$2,819,052	$ 196,270	$ 3,015,350	$ 142,851	$3,158,201
Restricted stock issued	697	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(93)	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(46)	—	—	—	—	—	(862)	—	(862)	—	(862)
Stock option exercises	14	—	—	—	—	—	272	—	272	—	272
Stock-based compensation	—	—	—	—	—	—	5,341	—	5,341	—	5,341
Conversion of common stock from Class C to Class A, net of tax	311	—	(311)	—	—	—	3,953	—	3,953	(3,373)	580
Net income (loss)	—	—	—	—	—	—	—	39,288	39,288	2,386	41,674
Balance at September 30, 2018	265,771	$ 27	12,003	$ 1	—	$ —	$2,827,756	$ 235,558	$ 3,063,342	$ 141,864	$3,205,206

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1—Basis of Presentation

Description of Business

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

Principles of Consolidation and Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") and the rules and regulations of the United States Securities and Exchange Commission ("SEC") for interim financial reporting. Accordingly, certain disclosures normally included in an Annual Report on Form 10-K have been omitted. The consolidated financial statements and related notes included in this Quarterly Report should be read in conjunction with the Company's consolidated financial statements and related notes included in the Company's Annual Report on Form 10-K for the period ended December 31, 2018 (the "2018 Annual Report"). Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in the Company's 2018 Annual Report.

In the opinion of management, all normal, recurring adjustments and accruals considered necessary to present fairly, in all material respects, the Company's interim financial results have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year.

The consolidated financial statements include the accounts of the Company and its majority owned subsidiary CRP, and CRP's wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. Noncontrolling interest represents third-party ownership in CRP, and it is presented as a component of equity. See *Note 8—Noncontrolling Interest* for further discussion of noncontrolling interest.

Use of Estimates

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

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

Income Taxes

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to the Company's year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various state jurisdictions, permanent and temporary differences and the likelihood of recovering deferred tax assets generated. The accounting estimates used to compute the provision for income taxes may change as new events occur, additional information becomes known or as the tax environment changes.

Recently Issued or Adopted Accounting Standards

In August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which updates the disclosure requirements for fair value measurements in Accounting Standard Codification ("ASC") Topic 820, *Fair Value Measurement* ("ASC Topic 820"). Certain disclosure requirements under ASC Topic 820 were removed, modified or added in order to improve the effectiveness of the fair value note included in the financial statements. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2019, including interim periods within those fiscal years. An entity is permitted to early adopt any removed or modified disclosures and delay adoption of the additional disclosures until the effective date. The Company is currently assessing the impact of this update on the Company's consolidated financial statements.

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

The standard permits retrospective application using either of the following methodologies: (i) application of the new standard at the earliest presented period or (ii) application of the new standard at the adoption date with a cumulative-effect adjustment recognized to retained earnings. The Company has adopted this guidance as of January 1, 2019 and elected to recognize a cumulative-effect adjustment at the time of adoption. The Company has elected the following practical expedients that allow an entity to carry forward historical accounting treatment relating to: (i) lease identification and classification for existing leases and (ii) existing land easements. The adoption of ASC 842 resulted in the recognition of *Operating lease right-of-use assets* and *Operating lease liabilities* in the Company's Consolidated Balance Sheets for its existing operating leases including drilling rig contracts, office rental agreements, and other wellhead equipment. This adoption did not have a significant impact on the Company's Consolidated Statements of Operations or Consolidated Statements of Cash Flows. Refer to *Note 13—Leases* for additional information.

Note 2—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	September 30, 2019	December 31, 2018
Accrued oil and gas sales receivable, net	$ 71,732	$ 66,997
Joint interest billings, net	65,444	31,658
Other	4,136	1,968
Accounts receivable, net	$ 141,312	$ 100,623

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	September 30, 2019	December 31, 2018
Accounts payable	$ 33,455	$ 55,984
Accrued capital expenditures	94,952	75,791
Revenues payable	85,275	63,399
Accrued interest	24,162	11,129
Accrued employee compensation and benefits	9,699	9,757
Accrued expenses and other	20,419	24,515
Accounts payable and accrued expenses	$ 267,962	$ 240,575

CENTENNIAL RESOURCE DEVELOPMENT, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 3—Long-Term Debt

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

(in thousands)	September 30, 2019	December 31, 2018
Credit Facility due 2023	$ 120,000	$ 300,000
5.375% Senior Notes due 2026	400,000	400,000
6.875% Senior Notes due 2027	500,000	—
Unamortized debt discount	(3,643)	—
Unamortized debt issuance costs on Senior Notes	(14,490)	(8,370)
Senior Notes, net	881,867	391,630
Total long-term debt, net	$ 1,001,867	$ 691,630

Credit Agreement

On May 4, 2018, CRP, the Company's consolidated subsidiary, entered into an amended and restated credit agreement with a syndicate of banks that as of September 30, 2019, had a borrowing base of $1.2 billion and elected commitments of $800.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of September 30, 2019, the Company had $120.0 million borrowings outstanding and $679.2 million in available borrowing capacity, which was net of $0.8 million in letters of credit outstanding.

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

Borrowings under CRP's revolving credit facility may be base rate loans or LIBOR loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for LIBOR loans. LIBOR loans bear interest at LIBOR (adjusted for statutory reserve requirements) plus an applicable margin, which ranged from 125 to 225 basis points as of September 30, 2019, depending on the percentage of the borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; or (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points, plus an applicable margin, which ranged from 25 to 125 basis points as of September 30, 2019, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee of 37.5 to 50 basis points on unused amounts under its facility. The applicable margins for the LIBOR loans and base rate loans referenced above reflect interest rate reductions that became effective on April 26, 2019 and are applicable as long as CRP's total leverage ratio (as described below) is less than or equal to 3.0 to 1.0. If CRP's total leverage ratio exceeds 3.0 to 1.0 in the future, the original applicable margins under the credit agreement would revert to the range from 150 to 250 basis points for LIBOR loans and 50 to 150 basis points for base rate loans, in each case depending on the percentage of the borrowing base utilized. The weighted-average borrowing rate on our credit agreement, exclusive of unutilized commitment fees and the letter of credit noted above, was 3.9% per annum for the nine months ended September 30, 2019.

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

CRP's credit agreement also requires it to maintain compliance with the following financial ratios: (i) a current ratio, which is the ratio of CRP's consolidated current assets (including unused commitments under its revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the credit agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP's credit agreement) to consolidated EBITDAX (as defined in CRP's credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with the covenants and the financial ratios described above as of September 30, 2019 and through the filing of this Quarterly Report.

Senior Unsecured Notes

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

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

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

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

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

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

The indentures governing the Senior Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP's ability and the ability of CRP's restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of September 30, 2019 and through the filing of this Quarterly Report.

Upon an Event of Default (as defined in the indentures governing the Senior Notes), the trustee or the holders of at least 25% of the aggregate principal amount of then outstanding Senior Notes may declare the Senior Notes immediately due and payable. In addition, a default resulting from certain events of bankruptcy or insolvency with respect to CRP, any restricted subsidiary of CRP that is a significant subsidiary, or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary, will automatically cause all outstanding Senior Notes to become due and payable.

Note 4—Asset Retirement Obligations

The following table summarizes the changes in the Company's asset retirement obligations ("ARO") associated with our working interests in oil and gas properties for the nine months ended September 30, 2019:

(in thousands)		
Asset retirement obligations as of January 1, 2019	$	13,895
Liabilities acquired		101
Liabilities incurred		1,075
Liabilities divested and settled		(1,112)
Accretion expense		670
Asset retirement obligations as of September 30, 2019	$	14,629

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

Note 5—Stock-Based Compensation

On October 7, 2016, the stockholders of the Company approved the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (the "LTIP"). An aggregate of 16,500,000 shares of Class A Common Stock were authorized for issuance under the LTIP, and as ofSeptember 30, 2019, the Company had 5,042,238 shares of Class A Common Stock available for future grants. The LTIP provides for grants of stock options (including incentive stock options and nonqualified stock options), stock appreciation rights, restricted stock, dividend equivalents, restricted stock units and other stock or cash-based awards.

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

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Restricted stock awards	$ 4,569	$ 2,393	$ 11,159	$ 6,157
Stock option awards	2,557	2,337	7,766	6,853
Performance stock units	918	611	2,360	1,319
Other stock-based compensation expense(1)	66	—	66	—
Total stock-based compensation expense	$ 8,110	$ 5,341	$ 21,351	$ 14,329

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

Restricted Stock

The following table provides information about restricted stock activity during thenine months ended September 30, 2019:

	Awards	Weighted Average Grant Date Fair Value
Unvested balance as of December 31, 2018	1,535,945	$ 17.88
Granted	3,906,196	6.70
Vested	(509,833)	17.82
Forfeited	(45,217)	12.96
Unvested balance as of September 30, 2019	4,887,091	8.99

The Company grants service-based restricted stock awards to executive officers and employees, which vest ratably over athree-year service period, and to directors, which vest over a one-year service period. Compensation cost for the service-based restricted stock awards is based on the market price of the Company’s Class A common stock on the grant date, and such costs are recognized ratably over the applicable vesting period. The weighted average grant-date fair value for restricted stock awards granted was $6.70 and $18.38 per share for the nine months ended September 30, 2019 and 2018, respectively. The total fair value of restricted stock awards that vested during the nine months ended September 30, 2019 and 2018 was $9.1 million and $4.4 million, respectively. Unrecognized compensation cost related to restricted shares that were unvested as of September 30, 2019 was $36.6 million, which the Company expects to recognize over a weighted average period of 2.4 years.

Stock Options

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

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

The following table summarizes the assumptions and related information used to determine the grant-date fair value of stock options awarded during thenine months ended September 30, 2019 and 2018:

	For the Nine Months Ended September 30,	
	2019	2018
Weighted average grant date fair value per share	$ 4.47	$ 7.74
Expected term (in years)	6	6
Expected stock volatility	46%	41%
Dividend yield	—%	—%
Risk-free interest rate	2.3%	2.6%

The following table provides information about stock option awards outstanding during thenine months ended September 30, 2019:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of December 31, 2018	4,559,334	$ 16.55		
Granted	326,000	9.56		
Exercised	—	—		
Forfeited	(65,336)	16.90		
Expired	(15,998)	17.88		
Outstanding as of September 30, 2019	4,804,000	16.07	7.5	$ —
Exercisable as of September 30, 2019	2,654,623	16.14	7.2	$ —

The total fair value of stock options that vested during thenine months ended September 30, 2019 and 2018 was $4.4 million and $3.7 million, respectively. The intrinsic value of stock options exercised was approximately $0.2 million for the nine months ended September 30, 2018 and there were no stock options exercised for the nine months ended September 30, 2019. As of September 30, 2019, there was $6.2 million of unrecognized compensation cost related to unvested stock options, which the Company expects to recognize on a pro-rata basis over a weighted average period of 1.5 years.

Performance Stock Units

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

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

The following table summarizes the key assumptions and related information used to determine the grant-date fair value of performance stock units awarded during the nine months ended September 30, 2019 and 2018:

	For the Nine Months Ended September 30,	
	2019	2018
Weighted average grant-date fair value per share	$ 6.68	$ 22.35
Number of simulations	1,000,000	1,000,000
Expected stock volatility	52.3%	40.2%
Dividend yield	—%	—%
Risk-free interest rate	1.8%	2.8%

The following table provides information about performance stock units outstanding during thenine months ended September 30, 2019:

	Awards	Weighted Average Grant Date Fair Value
Unvested balance as of December 31, 2018	386,459	$ 21.94
Granted	486,213	6.68
Vested	—	—
Forfeited	—	—
Unvested balance as of September 30, 2019	872,672	13.44

As of September 30, 2019, there was $6.7 million of unrecognized compensation cost related to performance stock units that were unvested, which the Company expects to recognize on a pro-rata basis over a weighted average period of 2.0 years.

Note 6—Derivative Instruments

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

Commodity Derivative Contracts

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

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

The following table summarizes the approximate volumes and average contract prices of swap contracts the Company had in place as ofSeptember 30, 2019:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl)[1]
Crude oil basis swaps	October 2019 - December 2019	920,000	10,000	$ (4.24)

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

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu)[1]
Natural gas swaps - Henry Hub	October 2019 - December 2019	2,760,000	30,000	$ 2.78
Natural gas swaps - West Texas WAHA	October 2019 - December 2019	1,380,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu)[2]
Natural gas basis swaps	October 2019 - December 2019	3,220,000	35,000	$ (1.31)

(1) These natural gas swap contracts are settled based on either i) the NYMEX Henry Hub price or ii) the Inside FERC West Texas WAHA price of natural gas, as applicable, as of the specified settlement date.

(2) These natural gas basis swap contracts are settled based on the difference between the Inside FERC's West Texas WAHA price and the NYMEX price of natural gas during each applicable settlement period.

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

The following table presents the impact of our derivative instruments in our Consolidated Statements of Operations for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	2019	2018	2019	2018
Net gain (loss) on derivative instruments	$ 1,522	$ (9,571)	$ (2,221)	$ 14,969

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

	Balance Sheet Classification	Gross Fair Value Asset/Liability Amounts	Gross Amounts Offset[(1)]	Net Recognized Fair Value Assets/Liabilities
(in thousands)		September 30, 2019		
Derivative Assets				
Commodity contracts	Current assets - Derivative instruments	$ 1,402	$ (1,402)	$ —
Derivative Liabilities				
Commodity contracts	Current liabilities - Derivative instruments	5,835	(1,402)	4,433
		December 31, 2018		
Derivative Assets				
Commodity contracts	Current assets - Derivative instruments	$ 7,708	$ (6,076)	$ 1,632
Derivative Liabilities				
Commodity contracts	Current liabilities - Derivative instruments	12,127	(6,076)	6,051

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

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

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

Note 7—Fair Value Measurements

Recurring Fair Value Measurements

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

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

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

(in thousands)	Level 1	Level 2	Level 3
September 30, 2019			
Total assets	$ —	$ —	$ —
Total liabilities	—	4,433	—
December 31, 2018			
Total assets	$ —	$ 1,632	$ —
Total liabilities	—	6,051	—

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

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and natural gas commodity derivatives. The Company uses industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied market volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations. Refer to *Note 6—Derivative Instruments* for details of the gross and net derivatives assets, liabilities and offset amounts presented in the Consolidated Balance Sheets.

Nonrecurring Fair Value Measurements

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

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include plugging costs and reserve lives. Refer to *Note 4—Asset Retirement Obligations* for additional information on the Company's ARO.

Other Financial Instruments

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

The Company's Senior Notes and borrowings under its credit agreement are recorded at cost. The following table summarizes the fair values and carrying values of these instruments as of September 30, 2019 and December 31, 2018:

	September 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair value
Credit facility due 2023[(1)]	$ 120,000	$ 120,000	$ 300,000	$ 300,000
5.375% Senior Notes due 2026[(2)]	392,369	382,480	391,630	372,000
6.875% Senior Notes due 2027[(2)]	489,498	498,750		

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

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

Note 8—Noncontrolling Interest

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

As of September 30, 2019, the noncontrolling interest ownership of CRP decreased to 0.4% from 4.3% as of December 31, 2018. The decrease was mainly the result of the exchange by the Centennial Contributors and their affiliates on September 17, 2019 of 10,860,144 of their CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock. A tax loss of $17.2 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner. No cash proceeds were received by the Company in connection with this exchange.

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

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Note 9—Earnings Per Share

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands, except per share data)	**2019**	**2018**	**2019**	**2018**
Net income (loss) attributable to Class A Common Stock	$ (3,585)	$ 39,288	$ 6,180	$ 168,919
Add: Income from conversion of Class C Common Stock	—	1,717	—	—
Adjusted net income (loss) attributable to Class A Common Stock	$ (3,585)	$ 41,005	$ 6,180	$ 168,919
Basic net earnings (loss) per share of Class A Common Stock	$ (0.01)	$ 0.15	$ 0.02	$ 0.64
Diluted net earnings (loss) per share of Class A Common Stock	$ (0.01)	$ 0.15	$ 0.02	$ 0.63
Basic weighted average shares of Class A Common Stock outstanding	266,205	263,959	265,025	263,029
Add: Dilutive effect of potential common shares	—	3,766	60	3,625
Add: Dilutive effects of conversion of Class C Common Stock	—	12,189	—	—
Diluted weighted average shares of Class A Common Stock outstanding	266,205	279,914	265,085	266,654

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**2019[(1)]**	**2018**	**2019**	**2018**
Out-of-the-money stock options	4,817	142	4,680	318
Warrants	8,000	—	8,000	—
Restricted stock	3,827	—	2,313	—
Weighted average shares of Class C Common Stock	10,351	—	11,446	13,056
Performance stock units	—	—	—	52
Employee Stock Purchase Plan	8		—	

(1) The Company recognized a net loss during the three months ended September 30, 2019. As a result, all potential common shares were anti-dilutive and excluded from the calculation of diluted net earnings per share.

Note 10—Transactions with Related Parties

Riverstone and its affiliates beneficially own more than 10% equity interest in the Company and are therefore considered related parties. The Company has a marketing agreement with Lucid Energy Delaware, LLC ("Lucid"), an affiliate of Riverstone. The Company believes that the terms of the marketing agreement with Lucid are no less favorable to either party than those held with unaffiliated parties. The following table summarizes the revenues recognized and the associated processing fees incurred from this marketing agreement as presented in the Consolidated Statements of Operations for the periods indicated as well as the related net receivables outstanding as of the balance sheet dates:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Oil and gas sales	$ 715	$ 1,300	$ 2,511	$ 1,745
Gathering, processing and transportation expenses	793	183	1,719	273

(in thousands)	**September 30, 2019**	**December 31, 2018**
Accounts receivable, net[(1)]	$ 192	$ 325

(1) The receivables are presented net of unpaid processing fees incurred as of the indicated period end date.

Note 11—Commitments and Contingencies

Commitments

The Company routinely enters into or extends operating agreements, office and equipment leases, drilling and completion rig contracts, among others, in the ordinary course of business. There has been no material, non-routine changes in commitments during the nine months ended September 30, 2019. Please refer to *Note 14—Commitments and Contingencies* included in Part II, Item 8 in the Company's 2018 Annual Report.

Contingencies

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

Note 12—Revenues

Revenue from Contracts with Customers

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Operating revenues (in thousands):				
Oil sales	$ 200,196	$ 184,510	$ 590,055	$ 533,507
Natural gas sales	11,070	14,311	31,655	46,612
NGL sales	17,864	36,059	66,228	88,422
Oil and gas sales	$ 229,130	$ 234,880	$ 687,938	$ 668,541

Oil sales

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

Natural gas and NGL sales

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

Performance obligations

For all commodity products, the Company records revenue in the month production is delivered to the purchaser. Settlement statements for natural gas and NGL sales may not be received for 30 to 90 days after the date production volumes are delivered and for crude oil, generally within 30 days after delivery has occurred. However, payment is unconditional once the performance obligations have been satisfied. At this time, the volume and price can be reasonably estimated and amounts due from customers are accrued in *Accounts Receivable, net* in the Consolidated Balance Sheets. As of September 30, 2019 and December 31, 2018, such receivable balances were $71.7 million and $67.0 million, respectively.

The Company records any differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Historically, any identified differences between revenue estimates and actual revenue received have not been significant. For both the nine months ended September 30, 2019 and 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods were not material.

Transaction price allocated to remaining performance obligations

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

Note 13—Leases

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

Currently, the Company has operating leases for drilling rig contracts, office rental agreements, and other wellhead equipment. As of September 30, 2019, these leases have remaining lease terms ranging from two months to three years, some of which include options to extend the lease term for up to five years, and some of which include options to early terminate. These options are considered in determining the lease term and are included in the present value of future payments that are recorded for leases when the Company is reasonably certain to exercise the option. Leases with an initial term of one year or less are not recorded in the Consolidated Balance Sheets. Additionally, none of the Company's lease agreements contain any material residual value guarantees or material restrictive covenants.

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

	As of September 30, 2019
Weighted-average discount rate	4.67%
Weighted-average remaining lease term (years)	1.26

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

Variable lease payments are recognized in the period in which they are incurred. Expenses related to short-term leases are recognized on a straight-line basis over the lease term. The following table presents the components of the Company's lease expenses for the periods presented.

(in thousands)	For the Three Months Ended September 30, 2019	For the Nine Months Ended September 30, 2019
Lease costs[(1)]		
Operating lease cost	$ 9,361	$ 30,754
Variable lease cost	1,819	3,323
Short-term lease cost	18,679	47,587
Total Lease Cost	$ 29,859	$ 81,664

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

Maturities of the Company's long-term operating lease liabilities by fiscal year as ofSeptember 30, 2019 are as follows:

(in thousands)	Total
2019[(1)(2)]	$ 6,428
2020	8,713
2021	2,855
2022	425
Total lease payments	18,421
Less: imputed interest	(408)
Present value of lease liabilities [(3)]	$ 18,013

(1) Excludes payments made during the nine months ended September 30, 2019.

(2) Includes drilling rigs as of September 30, 2019 with an initial term greater than one year.

(3) Of the total present value of lease liabilities, $14.2 million was recorded to current *Operating lease liabilities* and $3.9 million was recorded in noncurrent *Operating lease liabilities* in the Consolidated Balance Sheets as of September 30, 2019.

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

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

Note 14—Subsequent Events

Credit Facility Amendment

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operation

The following discussion and analysis of our financial condition and results of operation should be read in conjunction with the accompanying consolidated financial statements and related notes. The following discussion and analysis contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGLs, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed above in "Cautionary Statement Regarding Forward-Looking Statements" and in our 2018 Annual Report under the heading "Item 1A. Risk Factors," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

Centennial Resource Development, Inc. ("Centennial," "we," "us," or "our") is an independent oil and natural gas company focused on the development of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are primarily in the Delaware Basin, a sub-basin of the Permian Basin. Our capital programs are specifically focused on projects that we believe provide the greatest potential for return on capital.

Market Conditions

The oil and natural gas industry is cyclical, and commodity prices can be volatile. It is likely that commodity prices will continue to fluctuate due to global supply and demand, inventory levels, weather conditions, geopolitical events and other factors. For example, WTI spot prices for crude oil declined significantly to a low of $44.48 per barrel during the fourth quarter of 2018 but reached a high of $66.30 per barrel in the second quarter of 2019, while the average crude oil price remained below $60 per barrel during the first nine months of 2019.

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

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

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

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

2019 Highlights and Future Considerations

Operational Highlights

We operated, on average, a six-rig drilling program during the first nine months of 2019 which enabled us to complete and bring online 57 gross operated wells. The total number of completed wells during the first nine months of 2019 had an average effective lateral length of approximately 7,600 feet.

Financing Highlights

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

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

Results of Operations

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

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

	For the Three Months Ended September 30,		Increase/(Decrease)	
	2019	2018	$	%
Net revenues (in thousands):				
Oil sales	$ 200,196	$ 184,510	$ 15,686	9 %
Natural gas sales	11,070	14,311	(3,241)	(23)%
NGL sales	17,864	36,059	(18,195)	(50)%
Oil and gas sales	$ 229,130	$ 234,880	$ (5,750)	(2)%
Average sales prices:				
Oil (per Bbl)	$ 51.71	$ 55.68	$ (3.97)	(7)%
Effect of derivative settlements on average price (per Bbl)	(3.00)	2.56	(5.56)	(217)%
Oil net of hedging (per Bbl)	$ 48.71	$ 58.24	$ (9.53)	(16)%
Average NYMEX price for oil (per Bbl)	$ 56.45	$ 69.50	$ (13.05)	(19)%
Oil differential from NYMEX	(4.74)	(13.82)	9.08	66 %
Natural gas (per Mcf)	$ 0.96	$ 1.83	$ (0.87)	(48)%
Effect of derivative settlements on average price (per Mcf)	0.30	0.05	0.25	500 %
Natural gas net of hedging (per Mcf)	$ 1.26	$ 1.88	$ (0.62)	(33)%
Average NYMEX price for natural gas (per Mcf)	$ 2.33	$ 2.93	$ (0.60)	(20)%
Natural gas differential from NYMEX	(1.37)	(1.10)	(0.27)	(25)%
NGL (per Bbl)	$ 14.47	$ 30.85	$ (16.38)	(53)%
Net production:				
Oil (MBbls)	3,872	3,314	558	17 %
Natural gas (MMcf)	11,491	7,837	3,654	47 %
NGL (MBbls)	1,234	1,169	65	6 %
Total (MBoe)[1]	7,021	5,790	1,231	21 %
Average daily net production:				
Oil (Bbls/d)	42,079	36,027	6,052	17 %
Natural gas (Mcf/d)	124,896	85,180	39,716	47 %
NGL (Bbls/d)	13,417	12,706	711	6 %
Total (Boe/d)[1]	76,312	62,930	13,382	21 %

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

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the three months ended September 30, 2019 were $5.8 million (or 2%) lower than total net revenues for the three months ended September 30, 2018. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Average realized sales prices for oil, natural gas and NGLs decreased in the third quarter of 2019 compared to the same 2018 period. The average price for oil before the effects of hedging decreased 7%, the average price for natural gas before the effects of hedging decreased 48% and the average price for NGLs decreased 53% between periods. The 7% decrease in the average realized oil price was mainly the result of lower NYMEX crude prices between periods (average NYMEX prices decreased 19%), which was partially offset by improved oil differentials (a decrease of $9.08 per Bbl). The average realized sales price of natural gas decreased 48% due to lower average NYMEX gas prices between periods (average NYMEX prices decreased 20%) and wider gas differentials (an increase of $0.27 per Mcf). The continued widening of natural gas price differentials was due to natural gas pipeline takeaway capacity constraints impacting the Permian Basin, which has in turn depressed natural gas prices in West Texas. A new gas pipeline was placed into service late in the third quarter of 2019 in the Permian Basin and continued construction of additional natural gas pipelines are planned through 2021. These third party pipelines are expected to provide relief from these wider natural gas differentials. The overall 53% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products in the third quarter 2019 as compared to the third quarter of 2018.

The decreases in realized sales prices were partially offset by higher net production volumes between periods. Net production volumes for oil, natural gas and NGLs increased 17%, 47% and 6%, respectively, between periods. The oil volume increase resulted primarily from our drilling activities in the Delaware Basin. Since the third quarter 2018, we placed 79 gross operated wells on production in the Delaware Basin, which added 1,978 MBbls of net oil production to the third quarter of 2019. These oil volume increases were partially offset by normal field production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, which typically results in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. However, during the third quarter of 2019, the main processor of our wet gas temporarily switched from ethane-recovery to ethane-rejection due to lower ethane prices in the Permian Basin. This switch yielded an increased amount of natural gas recovered from our wet gas stream, which resulted in a significant increase in natural gas volumes between periods (up 47%) and a much lower increase (6%) in NGL volumes between periods. Our gas processor’s switch to ethane-rejection may not necessarily be a reoccurring trend for the remainder of 2019 or for future periods.

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

	For the Three Months Ended September 30,		Increase/(Decrease)	
	2019	2018	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 42,330	$ 23,706	$ 18,624	79 %
Severance and ad valorem taxes	12,213	14,410	(2,197)	(15)%
Gathering, processing and transportation expenses	20,853	16,090	4,763	30 %
Operating costs per Boe:				
Lease operating expenses	$ 6.03	$ 4.09	$ 1.94	47 %
Severance and ad valorem taxes	1.74	2.49	(0.75)	(30)%
Gathering, processing and transportation expenses	2.97	2.78	0.19	7 %

Lease Operating Expenses. Lease operating expenses (“LOE”) for the three months ended September 30, 2019 increased $18.6 million compared to the three months ended September 30, 2018. Higher LOE for the third quarter of 2019 was primarily related to a $14.9 million increase in expense associated with our higher well count. We had 319 gross operated horizontal wells as of September 30, 2019 as compared to 240 gross operated horizontal wells as of September 30, 2018. The net increase in well count was mainly due to our drilling activity adding 79 gross operated wells since the third quarter of 2018, which was further adjusted for acquisitions and divestitures. In addition, workover expense increased $3.7 million between periods as a result of our higher well count and related higher workover activity.

LOE on a per Boe basis increased when comparing the third quarter of 2019 to the same 2018 period. LOE per Boe was $6.03 for the third quarter of 2019, which represents an increase of $1.94 per Boe from the third quarter of 2018. This increase in rate was mainly due to the following factors: (i) a decline in the ratio of flush production to base production based on our level of D&C activity in 2019; (ii) higher monthly rental rates for electric submersible pumps (“ESPs”) and wellhead generators, (iii) increased wellhead chemical costs, (iv) increased number of field employees, resulting in higher labor costs, and (v) higher electricity rates incurred in the third quarter of 2019 associated with extreme heat in West Texas and associated demand.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the three months ended September 30, 2019 decreased $2.2 million compared to the three months ended September 30, 2018. Severance taxes are primarily based on the market value of production at the wellhead, while ad valorem taxes are generally based on the valuation of our proved developed oil and natural gas reserves and vary across the different counties in which we operate. Severance and ad valorem taxes as a percentage of total net revenues decreased to 5.3% for three months ended September 30, 2019 as compared to 6.1% for the same 2018 period. Severance taxes for three months ended September 30, 2019 were down $4.3 million compared to the third quarter of 2018 primarily due to $3.3 million in tax credits received in the 2019 period for wells that qualified for the “high-cost gas well” exemption, whose criteria are defined by the Texas Railroad Commission. Such decreases in severance taxes were partially offset byincreased ad valorem taxes of $2.1 million between periods as a result of our higher well count and higher oil and gas property values.

Severance and ad valorem taxes decreased on a per Boe basis to $1.74 for the third quarter of 2019 from $2.49 for the third quarter of 2018. This 30% decrease in rate is due to lower average realized sales prices for oil, natural gas and NGLs between periods, as well as "high cost gas" credits discussed above.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses ("GP&T") for the three months ended September 30, 2019 increased $4.8 million as compared to the three months ended September 30, 2018 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing costs, transportation tariffs and gathering fees being incurred.

On a per Boe basis, GP&T increased 7% from $2.78 for the third quarter of 2018 to $2.97 per Boe for the third quarter of 2019. However, these fees are mainly incurred on our volumes of natural gas and NGL processed, and the Boe rate on a natural gas and NGL volume basis (i.e. excluding crude oil barrels) was $6.62 for the three months ended September 30, 2019, which was consistent with our rate of $6.50 for the comparable 2018 period (2% higher).

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

	For the Three Months Ended September 30,	
(in thousands, except per Boe data)	**2019**	**2018**
Depreciation, depletion and amortization	$ 112,720	$ 83,423
Depreciation, depletion and amortization per Boe	$ 16.06	$ 14.41

Our DD&A rate can fluctuate as a result of development costs, acquisitions, impairments, as well as changes in proved reserves or proved developed reserves. For the three months ended September 30, 2019, DD&A expense amounted to $112.7 million, an increase of $29.3 million over the same 2018 period. The primary factor contributing to higher DD&A in 2019 was the increase in our overall production volumes between periods, which added $17.7 million of incremental DD&A expense to the third quarter of 2019, while higher DD&A rates between periods contributed an additional $11.6 million of DD&A expense to the third quarter of 2019.

DD&A per Boe was $16.06 for the third quarter of 2019 compared to $14.41 for the same period in 2018. The primary factors contributing to this higher DD&A rate were (i) revisions to proved and proved developed reserves subsequent to the third quarter of 2018 and (ii) a higher level of infrastructure costs (having no associated proved reserve adds).

Impairment and Abandonment Expense. During the three months ended September 30, 2019, $6.7 million of impairment expense was incurred related to the amortization of lease expiration costs associated with individually insignificant unproved properties. In the third quarter of 2018, $8.6 million of abandonment expense was incurred for undeveloped leasehold acreage that expired after efforts to extend, sell or trade these leases were unsuccessful.

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

	For the Three Months Ended September 30,	
(in thousands)	**2019**	**2018**
Geological and geophysical costs	$ 2,116	$ 2,259
Stock-based compensation	753	453
Exploration expense	$ 2,869	$ 2,712

Exploration expense was $2.9 million for the three months ended September 30, 2019 and was largely consistent with the $2.7 million incurred during the same prior year period. Exploration expense mainly consists of topographical studies, geographical and geophysical ("G&G") projects, and salaries and expenses of G&G personnel.

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

(in thousands)	For the Three Months Ended September 30, 2019	2018
Cash general and administrative expenses	$ 12,679	$ 11,673
Stock-based compensation	7,357	4,888
General and administrative expenses	$ 20,036	$ 16,561

G&A expenses for the three months ended September 30, 2019 were $20.0 million compared to $16.6 million for the third quarter of 2018. Our G&A expenses were higher in 2019 primarily due to $2.5 million in higher stock-based compensation and $0.6 million in increased software expenses.

Other Income and Expenses.

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

(in thousands)	For the Three Months Ended September 30, 2019	2018
Credit facility	$ 1,566	$ 1,364
5.375% Senior Notes due 2026	5,375	5,375
6.875% Senior Notes due 2027	8,594	—
Amortization of debt issuance costs and debt discount	783	452
Interest capitalized	(1,072)	(657)
Total	$ 15,246	$ 6,534

Interest expense was $8.7 million higher for the three months ended September 30, 2019 as compared to the three months ended September 30, 2018 primarily due to interest that was incurred in the third quarter of 2019 on our 2027 Senior Notes. These notes were issued in March of 2019; therefore, such interest was not similarly incurred in the 2018 period.

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

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

(in thousands)	For the Three Months Ended September 30, 2019	2018
Cash settlement gains (losses)	$ (8,218)	$ 8,866
Non-cash mark-to-market derivative gain (loss)	9,740	(18,437)
Total	$ 1,522	$ (9,571)

Income Tax Expense. We recognized income tax expense of $1.4 million and $11.7 million for the three months ended September 30, 2019 and 2018, respectively. The decrease in income tax expense for the three months ended September 30, 2019 was primarily due to lower pre-tax book income of $55.6 million from the third quarter of 2018 to the third quarter of 2019, which was partially offset by a $4.9 million discrete permanent item in the third quarter of 2019 that had the effect of increasing income tax expense for that period.

Our provision for income taxes for the third quarter of 2019 and 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax book income because of state income taxes and permanent differences.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

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

	For the Nine Months Ended September 30,		Increase/(Decrease)	
	2019	2018	$	%
Net revenues (in thousands):				
Oil sales	$ 590,055	$ 533,507	$ 56,548	11 %
Natural gas sales	31,655	46,612	(14,957)	(32)%
NGL sales	66,228	88,422	(22,194)	(25)%
Oil and gas sales	$ 687,938	$ 668,541	$ 19,397	3 %
Average sales prices:				
Oil (per Bbl)	$ 51.58	$ 59.27	$ (7.69)	(13)%
Effect of derivative settlements on average price (per Bbl)	(1.15)	1.50	(2.65)	(177)%
Oil net of hedging (per Bbl)	$ 50.43	$ 60.77	$ (10.34)	(17)%
Average NYMEX price for oil (per Bbl)	$ 57.05	$ 66.75	$ (9.70)	(15)%
Oil differential from NYMEX	(5.47)	(7.48)	2.01	27 %
Natural gas (per Mcf)	$ 1.04	$ 2.02	$ (0.98)	(49)%
Effect of derivative settlements on average price (per Mcf)	0.36	0.04	0.32	800 %
Natural gas net of hedging (per Mcf)	$ 1.40	$ 2.06	$ (0.66)	(32)%
Average NYMEX price for natural gas (per Mcf)	$ 2.57	$ 2.95	$ (0.38)	(13)%
Natural gas differential from NYMEX	(1.53)	(0.93)	(0.60)	(65)%
NGL (per Bbl)	$ 16.88	$ 29.08	$ (12.20)	(42)%
Net production:				
Oil (MBbls)	11,440	9,002	2,438	27 %
Natural gas (MMcf)	30,409	23,092	7,317	32 %
NGLs (MBbls)	3,923	3,040	883	29 %
Total (MBoe)(1)	20,431	15,891	4,540	29 %
Average daily net production:				
Oil (Bbls/d)	41,903	32,973	8,930	27 %
Natural gas (Mcf/d)	111,388	84,585	26,803	32 %
NGLs (Bbls/d)	14,371	11,137	3,234	29 %
Total (Boe/d)(1)	74,839	58,208	16,631	29 %

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

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the nine months ended September 30, 2019 were $19.4 million, or 3%, higher than total net revenues for the nine months ended September 30, 2018. Revenues are a function of oil, natural gas and NGL volumes sold and average commodity prices realized.

Net production volumes for oil, natural gas and NGLs increased 27%, 32% and 29%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin. Since the third quarter 2018, 79 gross operated wells were placed on production in the Delaware Basin, which added 5,024 MBbls of net oil production to the first nine months of 2019. These oil volume increases were partially offset by normal field production declines across our existing wells.

Natural gas and NGLs are produced concurrently with our crude oil volumes, typically resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. As a result, our natural gas production increased 32% and NGL production increased 29% during the first nine months of 2019 compared to the same prior year period.

The above increases in production volumes between periods were partially offset by lower average realized sales prices for oil, natural gas and NGLs for the first nine months of 2019 compared to the same 2018 period. The average price for oil before the effects of hedging decreased 13%, the average price for natural gas before the effects of hedging decreased 49% and the average price for NGLs decreased 42% between periods. The 13% decrease in the average realized oil price was the result of lower NYMEX crude prices between periods (average NYMEX oil prices decreased 15%) partially offset by improved oil differentials (a decrease of $2.01 per Bbl) during the first nine months of 2019. The average realized sales price of natural gas between periods decreased 49% due to lower average NYMEX gas prices between periods (average NYMEX prices decreased 13%) and wider gas differentials (an increase of $0.60 per Mcf). The continued widening of natural gas differentials was due to natural gas pipeline takeaway capacity constraints impacting the Permian Basin, which has in turn depressed natural gas in West Texas. A new gas pipeline was placed into service late in the third quarter of 2019 in the Permian Basin, and continued construction of additional natural gas pipelines are planned through 2021. These third party pipelines are expected to provide relief from these wider natural gas differentials. The overall 42% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products.

Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	For the Nine Months Ended September 30,		Increase/(Decrease)	
	2019	2018	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 107,077	$ 59,164	$ 47,913	81 %
Severance and ad valorem taxes	45,519	42,791	2,728	6 %
Gathering, processing and transportation expenses	52,120	45,214	6,906	15 %
Operating costs per Boe:				
Lease operating expenses	$ 5.24	$ 3.72	$ 1.52	41 %
Severance and ad valorem taxes	2.23	2.69	(0.46)	(17)%
Gathering, processing and transportation expenses	2.55	2.85	(0.30)	(11)%

Lease Operating Expenses. LOE for the nine months ended September 30, 2019 increased $47.9 million as compared to the nine months ended September 30, 2018. Higher LOE for the first nine months of 2019 was primarily related to a $31.1 million increase in expense associated with our higher well count. We had 319 gross operated horizontal wells as of September 30, 2019 compared to 240 gross operated horizontal wells as of September 30, 2018. The net increase in well count was mainly the result of our drilling activity adding 79 gross operated wells since the third quarter of 2018, which was further adjusted for acquisitions and divestitures. In addition, workover activity increased $16.8 million between periods as a result of our higher well count and related higher workover activity.

LOE on a per Boe basis increased when comparing the first nine months of 2019 to the same 2018 period. LOE per Boe was $5.24 for the nine months ended September 30, 2019, which represents an increase of $1.52 per Boe from the comparable 2018 period. This increase in rate was mainly due to our higher level of workover activity discussed above, as well as (i) a decline in the ratio of flush production to base production based on our level of D&C activity in 2019; (ii) higher monthly rental rates for ESPs and wellhead generators, (iii) increased wellhead chemical costs, and (iv) increased number of field employees, resulting in higher labor costs.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the nine months ended September 30, 2019 increased $2.7 million compared to the nine months ended September 30, 2018. Severance taxes are primarily based on the market value of our production at the wellhead, while ad valorem taxes are generally based on the valuation of our proved developed oil and natural gas properties and vary across the different counties in which we operate. Severance and ad valorem taxes as a percentage of total net revenues increased to 6.6% for the nine months ended September 30, 2019 as compared to 6.4% in 2018 period. Ad valorem taxes increased $5.3 million between periods as a result of our higher well count and higher oil and gas property values. These increases in ad valorem taxes were partially offset by lower severance taxes of $2.6 million between periods primarily related to tax credits received in the first nine months of 2019 from wells that qualified for the “high-cost gas well” exemption, whose criteria are defined by the Texas Railroad Commission.

Severance and ad valorem taxes decreased on a per Boe basis to $2.23 for the nine months ended September 30, 2019 from $2.69 for the nine months ended September 30, 2018. This 17% decrease in rate is due to lower average realized sales prices for oil, natural gas and NGLs between periods.

Gathering, Processing and Transportation Expenses. GP&T for the nine months ended September 30, 2019 increased $6.9 million compared to the nine months ended September 30, 2018 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing costs, transportation tariffs and gathering fees being incurred.

On a per Boe basis, GP&T decreased 11% from $2.85 for the first nine months of 2018 to $2.55 per Boe for the same 2019 period. On a natural gas and NGL volume basis (i.e. excluding crude oil barrels) the Boe rate likewise decreased between periods to $5.80 from $6.56 for the nine months ended September 30, 2019 and 2018, respectively. This decrease was attributable to the following factors: (i) lower natural gas prices between periods, as residue gas is a primary cost component of gas processing fees; and (ii) $11.9 million in reimbursements received from third parties for their usage of our firm transportation capacity in the first nine months of 2019, which were not similarly received in 2018. The agreement that enables us to receive these third party reimbursements extends through March of 2020; such reimbursements, however, may not necessarily be recurring in these similar amounts.

Depreciation, Depletion and Amortization. The following table summarizes our DD&A for the periods indicated:

	For the Nine Months Ended September 30,	
(in thousands, except per Boe data)	**2019**	**2018**
Depreciation, depletion and amortization	$ 321,392	$ 224,379
Depreciation, depletion and amortization per Boe	$ 15.73	$ 14.12

DD&A rate can fluctuate as a result of finding and development costs, acquisitions, impairments, as well as changes in proved reserve or proved developed reserves. For the nine months ended September 30, 2019, DD&A expense amounted to $321.4 million, an increase of $97.0 million over the same 2018 period. The primary factor contributing to higher DD&A in 2019 was the increase in our overall production volumes between periods, which added $64.3 million of incremental DD&A expense during the first nine months of 2019, while higher DD&A rates between periods contributed an additional $32.7 million of DD&A expense to the first nine months of 2019.

DD&A per Boe was $15.73 for the nine months of 2019 compared to $14.12 for the same period in 2018. The primary factors contributing to this higher DD&A rate were (i) revisions to proved and proved developed reserves subsequent to the third quarter of 2018 and (ii) a higher level of infrastructure costs (having no associated proved reserve adds).

Impairment and Abandonment Expenses. During the nine months ended September 30, 2019, $42.4 million of impairment and abandonment expense was incurred related to undeveloped leasehold acreage. This expense consisted of the following: (i) $19.1 million related to non-core acreage that expired during the first nine months of 2019 after efforts to extend, sell or trade these leases were unsuccessful, (ii) $16.6 million for impaired acreage following an acreage sale initiated in the first quarter of 2019, and (iii) $6.7 million related to the amortization of leasehold expiration costs associated with individually insignificant unproved properties.

During the nine months ended September 30, 2018, $10.4 million of abandonment expense was incurred related to undeveloped leasehold acreage that expired during the period after efforts to extend, sell or trade these leases were unsuccessful.

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

	For the Nine Months Ended September 30,	
(in thousands)	**2019**	**2018**
Geological and geophysical costs	$ 7,212	$ 6,308
Stock-based compensation	2,034	1,323
Exploratory dry hole costs	—	395
Exploration expense	$ 9,246	$ 8,026

Exploration was $9.2 million for the nine months ended September 30, 2019 compared to $8.0 million for the same prior year period. Exploration expense mainly consists of topographical studies, G&G projects, and salaries and expenses of G&G personnel. The period over period increase in exploration expense was primarily due to an increase in G&G personnel expenses of $2.2 million during the first nine months of 2019 due to the average number of geologists increasing between periods. This increase was partially offset by lower costs incurred on G&G projects and seismic studies between periods and no exploratory dry hole costs incurred during 2019.

General and Administrative Expenses. The following table summarizes our G&A expenses for the periods indicated:

	For the Nine Months Ended September 30,	
(in thousands)	2019	2018
Cash general and administrative expenses	$ 37,272	$ 31,661
Stock-based compensation	19,317	13,006
General and administrative expenses	$ 56,589	$ 44,667

G&A expenses for the nine months ended September 30, 2019 were $56.6 million compared to $44.7 million for the nine months ended September 30, 2018. The higher G&A expenses incurred in 2019 were primarily due to $4.4 million in increased employee salaries, wages and payroll burdens, $6.3 million in higher stock-based compensation and $1.7 million in increased software costs and office rental expenses. These costs were higher during the first nine months of 2019 due to our increase in headcount since September 30, 2018.

Other Income and Expenses.

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

	For the Nine Months Ended September 30,	
(in thousands)	2019	2018
Credit facility	$ 6,179	$ 2,835
5.375% Senior Notes due 2026	16,124	16,125
6.875% Senior Notes due 2027	18,716	—
Amortization of debt issuance costs and debt discount	2,070	1,258
Interest capitalized	(3,246)	(2,080)
Total	$ 39,843	$ 18,138

Interest expense was $21.7 million higher for the nine months ended September 30, 2019 compared to the same 2018 period primarily due to $18.7 million in interest we incurred in the first nine months of 2019 related to our 2027 Senior Notes that were issued in March 2019, as well as increased borrowings under our credit facility in the first nine months of 2019. Our weighted average borrowings outstanding under our credit facility were $138.3 million and $45.2 million for the first nine months of 2019 and 2018, respectively. Our credit facility's weighted average effective interest rate was 3.9% for the nine months ended September 30, 2019 as compared to 3.7% for the same 2018 period.

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

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

	For the Nine Months Ended September 30,	
(in thousands)	2019	2018
Cash settlement gains (losses)	$ (2,207)	$ 14,390
Non-cash mark-to-market derivative gain (loss)	(14)	579
Total	$ (2,221)	$ 14,969

Income Tax Expense. During the nine months ended September 30, 2019 and 2018, we recognized income tax expense of $5.1 million and $50.7 million, respectively. The decrease in income tax expense for the nine months ended September 30, 2019 as compared to the same period in 2018 was primarily due to a decrease in pre-tax income of $218.8 million between periods, which was partially offset by a $5.7 million discrete permanent item in the first nine months of 2019 that had the effect of increasing income tax expense for that period.

Our provision for income taxes for the first nine months of 2019 and 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax income because of state income taxes and permanent differences.

Liquidity and Capital Resources

Overview

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

The following table summarizes our capital expenditures ("capex") incurred for thenine months ended September 30, 2019:

(in millions)	For the Nine Months Ended September 30, 2019
Drilling and completion capital expenditures	$ 528.7
Facilities, infrastructure and other	130.8
Land	35.2
Total capital expenditures	$ 694.7

We continually evaluate our capital needs and compare them to our capital resources. Our estimated capex budget for 2019 is $765 million to $925 million, of which $625 million to $725 million is allocated to drilling and completion ("D&C") activity. We expect to fund our capex budget with cash flows from operations and borrowings under our credit facility. The D&C portion of our 2019 capital budget represents a decrease relative to $766.1 million of D&C expenditures incurred during 2018. This decreased capital budget is due to running fewer drilling rigs in 2019 versus 2018.

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

Based upon current oil and natural gas price expectations for the remainder of2019, we believe that our cash flows from operations, proceeds from the issuance of the 2027 Senior Notes and borrowings under our credit facility will provide us with sufficient liquidity to execute our current capital program. However, our future cash flows are subject to a number of variables, including the future level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot ensure that operations and other needed capital will be available on acceptable terms or at all. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce our expected level of capital expenditures and/or seek additional sources for funding capital investments. As we pursue our future development program, we are actively assessing the correct mix of reserve-based borrowings and debt offerings. If we require additional capital to fund acquisitions, we may also seek such capital through traditional reserve-based borrowings, offerings of debt or equity securities, asset sales, or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Analysis of Cash Flow Changes

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

(in thousands)	For the Nine Months Ended September 30, 2019	2018
Net cash provided by operating activities	$ 384,875	$ 494,695
Net cash used in investing activities	(698,120)	(694,966)
Net cash provided by financing activities	308,064	135,511

For the nine months ended September 30, 2019, we generated $384.9 million of cash from operating activities, a decrease of$109.8 million from the same period in 2018. Cash provided by operating activities decreased primarily due to lower realized prices for crude oil, natural gas and NGLs, higher lease operating expenses, severance and ad valorem taxes, GP&T costs, exploration expense, cash general and administrative expenses, interest payments, cash settlement losses from derivatives and the timing of our receivable collections during the nine months ended September 30, 2019. These declining factors were partially offset by higher crude oil, natural gas and NGL production volumes and the timing of supplier payments for the nine months ended September 30, 2019 as compared to the same 2018 period. Refer to “Results of Operations” for more information on the impact of volumes and prices on revenues and for more information on fluctuations in our operating expenses between periods.

During the nine months ended September 30, 2019, cash flows from operating activities, cash on hand, proceeds from sales of oil and gas properties and proceeds from the issuance of our 2027 Senior Notes were used to repay net borrowings of $180.0 million under our credit facility, to finance $644.9 million of drilling and development capex, to fund $73.3 million in oil and gas property acquisitions and to purchase $8.2 million of other property and equipment.

During the nine months ended September 30, 2018, cash flows from operating activities, cash on hand, proceeds from sales of oil and gas properties and $140.0 million in net borrowings under our credit facility were used to finance $723.1 million of drilling and development capex and $114.9 million in oil and gas property acquisitions.

Credit Agreement

On May 4, 2018, CRP, our consolidated subsidiary, entered into an amended and restated credit agreement with a syndicate of banks that as of September 30, 2019, had a borrowing base of $1.2 billion and elected commitments of $800.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of September 30, 2019, we had $120.0 million borrowings outstanding and $679.2 million in available borrowing capacity, which was net of $0.8 million in letters of credit outstanding. In connection with the fall 2019 semi-annual borrowing base redetermination under our credit facility, the borrowing base was reaffirmed at $1.2 billion and the amount of elected commitments remained at $800.0 million.

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

CRP’s credit agreement also requires it to maintain compliance with the following financial ratios: (i) a current ratio, which is the ratio of CRP’s consolidated current assets (including unused commitments under its revolving credit facility and excluding non-cash derivative assets and certain restricted cash) to its consolidated current liabilities (excluding the current portion of long-term debt under the credit agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and (ii) a leverage ratio, which is the ratio of Total Funded Debt (as defined in CRP’s credit agreement) to consolidated EBITDAX (as defined in CRP’s credit agreement) for the rolling four fiscal quarter period ending on such day, of not greater than 4.0 to 1.0. CRP was in compliance with these covenants and the financial ratios described above as of September 30, 2019 and through the filing of this Quarterly Report.

For further information on our credit agreement, refer to *Note 3—Long-Term Debt* under Part I, Item I of this Quarterly Report.

Senior Notes

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

The indentures governing the Senior Notes contain covenants that, among other things and subject to certain exceptions and qualifications, limit CRP’s ability and the ability of CRP’s restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. CRP was in compliance with these covenants as of September 30, 2019 and through the filing of this Quarterly Report.

For further information on our Senior Notes, refer to *Note 3—Long-Term Debt* under Part I, Item I of this Quarterly Report.

Contractual Obligations

Our contractual obligations include drilling rig commitments, office leases, water disposal agreements, purchase obligations, asset retirement obligations, long-term debt obligations, cash interest expense on long-term debt obligations and transportation and gathering agreements. Since December 31, 2018, there have not been any significant, non-routine changes in our contractual obligations, other than the issuance of 2027 Senior Notes and their related interest obligations as discussed in *Note 3—Long-Term Debt* under Part I, Item 1. of this Quarterly Report.

Critical Accounting Policies and Estimates

There have been no material changes during the nine months ended September 30, 2019 to the critical accounting policies previously disclosed in our2018 Annual Report. Please refer to Part II, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates* in our 2018 Annual Report for a discussion of our critical accounting policies and estimates.

New Accounting Pronouncements

Please refer to *Note 1—Basis of Presentation* under Part I, Item 1. of this Quarterly Report for a discussion of the effects of recently adopted accounting standards and the potential effects of new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Our primary market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. Based on our production for the first nine months of 2019, our oil and gas sales for the nine months ended September 30, 2019 would have moved up or down $59.0 million for each 10% change in oil prices per Bbl, $6.6 million for each 10% change in NGL prices per Bbl, and $3.2 million for each 10% change in natural gas prices per Mcf.

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

The following table summarizes the terms of the swap contracts we had in place as of September 30, 2019 and additional contracts entered into through October 31, 2019. Refer to *Note 7-Derivative Instruments* in Item 1 of Part I of this Quarterly Report for open derivative positions as of September 30, 2019:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl)(1)
Crude oil basis swaps	October 2019 - December 2019	920,000	10,000	$ (4.24)
	January 2020 - March 2020	273,000	3,000	0.67
	April 2020 - June 2020	273,000	3,000	0.67
	July 2020 - September 2020	276,000	3,000	0.67
	October 2020 - December 2020	276,000	3,000	0.67

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

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu)(1)
Natural gas swaps - Henry Hub	October 2019 - December 2019	2,760,000	30,000	$ 2.78
Natural gas swaps - West Texas WAHA	October 2019 - December 2019	1,380,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu)(2)
Natural gas basis swaps	October 2019 - December 2019	3,220,000	35,000	$ (1.31)

(1) These natural gas swap contracts are settled based on either i) the NYMEX Henry Hub price or ii) the Inside FERC West Texas WAHA price of natural gas, as applicable, as of the specified settlement date.

(2) These natural gas basis swap contracts are settled based on the difference between the Inside FERC's West Texas WAHA price and the NYMEX price of natural gas during each applicable settlement period.

Changes in the fair value of derivative contracts from December 31, 2018 to September 30, 2019, are presented below:

(in thousands)		Commodity derivative asset (liability)
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2018	$	(4,419)
Contracts settled		2,207
Change in the futures curve of forecasted commodity prices[1]		(2,221)
Net fair value of oil and gas derivative contracts outstanding as of September 30, 2019	$	(4,433)

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

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2019 would cause a less than $0.1 million increase or decrease, respectively, in this fair value liability, and a hypothetical upward or downward shift of 10% per Mcf in the NYMEX forward curve for natural gas as of September 30, 2019 would cause a $0.6 million increase or decrease, respectively, in this same fair value liability.

Interest Rate Risk

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

As of September 30, 2019, we had $120.0 million of debt outstanding under our credit agreement, with a weighted average interest rate of 3.3%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would be approximately $1.2 million per year. We do not currently have or intend to enter into any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

The remaining long-term debt balance of $881.9 million consists of our Senior Notes, which have fixed interest rates; therefore, this balance is not affected by interest rate movements. For additional information regarding our debt instruments, see *Note 3—Long-Term Debt*, in Item 1 of Part I of this Quarterly Report.

Item 4. Controls and Procedures

Evaluation of Disclosure Control and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Exchange Act, we have evaluated, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2019 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in the system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the three months ended September 30, 2019 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" included in our 2018 Annual Report and the risk factors and other cautionary statements contained in our other SEC filings, which could materially affect our businesses, financial condition, or future results. 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 described in our 2018 Annual Report or our other SEC filings.

Item 5. Other Information

On October 29, 2019, the board of directors of the Company approved the Centennial Resource Development, Inc. Amended and Restated Severance Plan (the "Amended Plan"). Under the Amended Plan, all of the Company's full-time employees, including the named executive officers, are eligible for benefits in connection with a Qualifying Termination of employment following a Change of Control (as such capitalized terms are defined in the Amended Plan). The Amended Plan amends and restates in its entirety the Centennial Resource Development, Inc. Severance Plan that became effective on May 2, 2018 to (a) increase the cash severance payable to employees that experience a Qualifying Termination following a Change of Control, (b) broaden the definition of "Qualifying Termination" as it relates to non-officer employees to include situations where an employee resigns for Good Reason (as defined in the Amended Plan), and (c) provide for the potential reduction of benefits in certain instances to avoid excise tax liability.

Under the Amended Plan, if one of the Company's named executive officers experiences a Qualifying Termination, the named executive officer is entitled to cash severance in an amount equal to 225% (or, in the case of the Chief Executive Officer, 275%) of the executive officer's annual base salary, *plus* 225% (or, in the case of the Chief Executive Officer, 275%) of the average of the actual annual performance bonuses paid to the executive officer in the three full fiscal years prior to the year of termination. The Amended Plan makes no changes to the healthcare continuation benefits, outplacement benefits or equity treatment benefits that the named executive officers are entitled to receive following a Qualifying Termination, all of which is described in the Company's 2019 Proxy Statement.

The foregoing description is qualified in its entirety by reference to the full text of the Amended Plan, a copy of which is attached hereto as Exhibit 10.3 and is incorporated herein by reference.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
3.1	Third Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019).
3.2	Second Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on May 1, 2019).
3.3	Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of October 11, 2016 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.4	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of December 28, 2016 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 29, 2016).
3.5	Amendment No. 2 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of March 20, 2017 (incorporated by reference to Exhibit 3.5 to the Company's Annual Report on Form 10-K filed with the SEC on March 23, 2017).
3.6	Amendment No. 3 to Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC dated as of June 15, 2018 (incorporated by reference to Exhibit 3.6 to the Company's Quarterly Report on Form 10-Q filed with the SEC on August 6, 2018).
10.1#	Centennial Resource Development, Inc. Second Amended and Restated Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed with the SEC on August 5, 2019).
10.2#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed with the SEC on August 5, 2019).
10.3*#	Centennial Resource Development, Inc. Amended and Restated Severance Plan.
31.1*	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
101.INS*	Inline XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.

Management contract or compensatory plan or agreement.

* Filed herewith.

SIGNATURES

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

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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

Date: November 4, 2019

EXHIBIT 10.3

CENTENNIAL RESOURCE DEVELOPMENT, INC.
AMENDED AND RESTATED SEVERANCE PLAN

I. PURPOSE

The purpose of this Centennial Resource Development, Inc. Amended and Restated Severance Plan (the "Plan") is to encourage employees of Centennial Resource Development, Inc. (together with any successor, the "Company") and its subsidiaries to remain in the employ of the Employer by providing, among other things, severance protections to such employees in the event their employment is terminated under the circumstances described in this Plan. This Plan supersedes, and amends and restates in its entirety, the Centennial Resource Development, Inc. Severance Plan.

II. DEFINITIONS

For purposes of this Plan, the following terms shall have the meanings set forth below:

A. "Administrator" means the Committee or any other committee designated by the Board to administer the Plan.

B. "Affiliate" means with respect to any person or entity, any other person or entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person or entity. For purposes of this definition, "control," when used with respect to any person or entity, means the power to direct the management and policies of such person or entity, directly or indirectly, whether through ownership of voting securities, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

C. "Average Adjusted Bonus" means, with respect to a Participant, the average of the actual annual performance bonuses paid to the Participant, whether paid in cash or property, for the three full fiscal years of service to the Employer (or such fewer number of full fiscal years as the Participant has performed services for the Employer and been eligible for an annual performance bonus from the Employer) immediately preceding the fiscal year in which the Termination Date occurs, excluding any portion of an annual bonus that the Company reasonably determines is attributable to payment of a portion of the annual bonus in property and is over and above the amount of the annual bonus that the Participant would have been paid if the Participant's entire annual bonus had been paid in cash.

D. "Base Salary" means, with respect to any Participant, the Participant's base salary at the rate in effect on the Participant's Termination Date, disregarding for this purpose any decrease in base salary that provides a basis for Good Reason.

E. "Board" means the Board of Directors of the Company.

F. "Cause" means, with respect to a Participant, the Participant's (i) refusal to perform substantially the Participant's duties with the Employer (other than any such failure resulting from incapacity due to physical or mental illness), which failure remains uncured for thirty (30) days following notice thereof delivered to the Participant by the Employer, (ii) willful engagement in conduct that is materially injurious to the Company or its Affiliate or (iii) commission of a crime or an act of fraud, theft, misappropriation or embezzlement that could reasonably be expected to materially impair the Participant's ability to substantially perform the Participant's duties with the Employer. No act of the Participant will be considered "willful" unless it is done by the Participant without a reasonable belief that the act was in the best interests of the Company and its Affiliates.

G. "Change in Control" means a "Change in Control" as defined in the LTIP. Notwithstanding the foregoing, if a Change in Control constitutes a payment event with respect to any amount which constitutes or provides for the deferral of compensation and is subject to Section 409A, the transaction or event with respect to such amount must also constitute a "change in control event," as defined in Treasury Regulation Section 1.409A-3(i)(5) to the extent required by Section 409A.

H. "CIC Bonus" means (i) with respect to any Participant with an Employment Level below Vice President, the Target Bonus Amount, prorated based on the number of full calendar months of the fiscal year prior to and including the calendar month in which the Termination Date occurs or (ii) with respect to a Participant with an Employment Level of Vice President or higher, the Average Adjusted Bonus.

I. "CIC Protection Period" means, with respect to a Participant, the period of time set forth opposite the Participant's Employment Level under the heading "CIC Protection Period" on Schedule A.

J. "CIC Severance Multiplier" means, with respect to a Participant, the number set forth opposite the Participant's Employment Level under the heading "CIC Severance Multiplier" on Schedule A.

K. "CIC Severance Period" means, with respect to a Participant, the period of time set forth opposite the Participant's Employment Level under the heading "CIC Severance Period" on Schedule A.

L. "COBRA" means the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended.

M. "Code" means the Internal Revenue Code of 1986, as amended from time to time, or any successor statute thereto, and the regulations promulgated thereunder, as in effect from time to time.

N. "Committee" means the Compensation Committee of the Board.

O. "Effective Date" means the date this Plan was approved by the Board.

P. "Employer" means, with respect to a Participant, the Company and its subsidiary that employs the Participant.

Q. "Employment Level" means, with respect to a Participant, the Participant's employment level with the Employer as in effect at the time of the Participant's Qualifying Termination.

R. "Good Reason" means, with respect to a Participant, the occurrence of any of the following without the Participant's prior written consent: (i) solely with respect to a Participant with an Employment Level of Vice President or higher, a material diminution in the Participant's responsibilities, authority and duties as an employee of the Employer, (ii) a material reduction in Participant's base salary or target annual bonus opportunity, (iii) a requirement by the Employer that the Participant relocate the Participant's principal location of employment to a location that is more than fifty (50) miles from the Participant's principal work location as of the occurrence of the first Change in Control following the Effective Date or (iv) the Company's failure to cause a Successor to assume the liabilities under this Plan as required under Section VI; provided that with respect to the events described in clauses (i) through (iii), no Good Reason will have occurred unless and until (x) the Participant has provided the Employer, within ninety (90) days of the Participant's knowledge of the occurrence of the facts and circumstances underlying the Good Reason event, notice stating with reasonable specificity the applicable facts and circumstances constituting Good Reason, (y) the Participant has provided the Employer with an opportunity to cure, and the Employer has not cured, the same within thirty (30) days after the receipt of such notice and (z) the Participant terminates the Participant's employment within one-hundred eighty (180) days after the end of the cure period.

S. "LTIP" means the Company's 2016 Long Term Incentive Plan.

T. "Outplacement Benefits" means, with respect to a Participant, employment outplacement services to be provided by a provider selected by the Employer during the period of time set forth opposite the Participant's Employment Level under the heading "Outplacement Services Period" on Schedule A.

U. "Qualifying Termination" means, with respect to a Participant, a termination of the Participant's employment with the Employer by the Employer without Cause or by the Participant for Good Reason, in either case, which occurs during the CIC Protection Period.

V. "Section 409A" means Section 409A of the Code.

W. "Successor" means any employer (whether or not the employer is an Affiliate of the Company) which acquires (through merger, consolidation, reorganization, transfer, sublease, assignment or otherwise) all or substantially all of the business or assets of the Company or of a division or business of the Company.

X. "Target Bonus Amount" means, with respect to a Participant, the Participant's target annual performance bonus amount, if any, in effect at the time of the Participant's Qualifying Termination, disregarding for this purpose any decrease in target annual performance bonus that provides a basis for Good Reason.

Y. "Termination Date" means, with respect to a Participant, the date on which a termination of the Participant's employment is effective.

III. ELIGIBILITY

The participants in this Plan ("Participants") are all regular U.S. full-time employees of the Company and its direct and indirect subsidiaries.

IV. BENEFITS

Upon termination of a Participant's employment with the Employer for any reason, the Participant will be entitled to receive payment of any earned but unpaid Base Salary and any other amounts or benefits, including accrued paid time off to the extent payable upon termination pursuant to the Employer's policies, under the Employer's employee benefit plans, programs or arrangements to which the Participant is entitled pursuant to the terms of such plans, programs or arrangements or applicable law, payable in accordance with the terms of such plans, programs or arrangements or as otherwise required by applicable law (collectively, "Accrued Rights").

If a Participant experiences a Qualifying Termination, then subject to Sections V, VI and VII, the Participant will be entitled to receive the following payments and benefits:

A. A cash payment, paid in a single installment within sixty (60) days following the Termination Date, equal to the sum of (i) the annual Base Salary multiplied by the CIC Severance Multiplier, (ii) the CIC Bonus multiplied by the CIC

Severance Multiplier and (iii) 125% of the aggregate COBRA premiums, based on the COBRA premium rates in effect for the month in which the Termination Date occurs, that the Participant would need to pay to continue coverage for the Participant and the Participant's covered beneficiaries under the Employer's group health plans during the CIC Severance Period;

B. The Outplacement Benefits;

C. All unvested equity or equity-based awards under any Company equity compensation plans that vest solely based upon the passage of time shall immediately become 100% vested; and

D. All unvested equity or equity-based awards under any Company equity compensation plans that vest in whole or in part based upon the attainment of performance vesting conditions shall become vested at the level that would apply based on actual performance calculated as if the Termination Date was the final day of the applicable performance period (without any reduction to the overall award to reflect the shortened performance period).

V. RELEASE OF CLAIMS

Notwithstanding any provision of this Plan to the contrary, any payments and benefits provided to a Participant under this Plan, other than the Accrued Rights, shall be subject to and contingent upon (i) the Participant's execution and delivery following the Termination Date of a general release of claims in a form reasonably satisfactory to the Company that becomes effective within forty-five (45) days following the Termination Date and (ii) the Participant not revoking the foregoing release within seven (7) days after its execution and delivery to the Company.

VI. OFFERS OF EMPLOYMENTS; SUCCESSORS

Any Participant with an Employment Level below Vice President shall not be entitled to benefits under this Plan if the Participant rejects or fails to accept a written offer of employment from a Successor or from any Affiliate of the Company made on or before his or her Termination Date that the Company reasonably determines is for substantially comparable employment. The Company will require any Successor that does not assume the Employer's obligations under this Plan by operation of law to expressly assume and agree to perform this Plan in the same manner and to the same extent that the Employer would be required to perform if no such succession had taken place.

VII. TAX MATTERS

1. Withholding

The Employer may deduct and withhold from any amounts payable under this Plan such federal, state, local, foreign or other taxes as are required to be withheld pursuant to any applicable law or regulation.

2. Non-Qualified Deferred Compensation

The payments and benefits under this Plan are intended to comply with or be exempt from Section 409A and, accordingly, to the maximum extent permitted, this Plan shall be interpreted to be in compliance therewith. Notwithstanding any provision of this Plan to the contrary, in the event that the Administrator determines that any amounts payable hereunder will be immediately taxable to any Participant under Section 409A, the Administrator may (without any obligation to do so or to indemnify the Participant for failure to do so) (A) adopt such amendments to this Plan or adopt such other policies and procedures (including amendments, policies and procedures with retroactive effect) that it determines to be necessary or appropriate to preserve the intended tax treatment of the benefits provided by this Plan or the economic benefits of this Plan and (B) take such other actions it determines to be necessary or appropriate to exempt the amounts payable hereunder from Section 409A or to comply with the requirements of Section 409A and thereby avoid the application of penalty taxes thereunder.

Notwithstanding any provision of this Plan to the contrary, no termination or other similar payments and benefits under this Plan will be payable to a Participant unless the Participant's termination of employment constitutes a "separation from service" within the meaning of Section 409A (a "Separation from Service").

Notwithstanding any provision of this Plan to the contrary, if a Participant is deemed by the Company at the time of the Participant's Separation from Service to be a "specified employee" for purposes of Section 409A, to the extent delayed commencement of any portion of the benefits to which the Participant is entitled under this Plan is required in order to avoid a prohibited distribution under Section 409A, such portion of the Participant's benefits will not be provided to the Participant prior to the earlier of (i) the expiration of the six-month period measured from the date of the Participant's Separation from Service or (ii) the date of the Participant's death. As promptly as possible following the expiration of the applicable Section 409A period, all payments and benefits deferred pursuant to the preceding sentence will be paid in a lump sum to a Participant (or the Participant's estate), and any remaining payments due to the Participant under this Plan will be paid as otherwise provided herein.

A Participant's right to receive any installment payments under this Plan shall be treated as a right to receive a series of separate payments and, accordingly, each such installment payment shall at all times be considered a separate and distinct payment as permitted under Section 409A.

3. Potential Reduction of Certain "Parachute Payments"

A. Notwithstanding any other provisions of this Plan, in the event that any payment or benefit by the Company or otherwise to or for the benefit of a Participant, whether paid or payable or distributed or distributable pursuant to the terms of this Plan (all such payments and benefits, including the payments and benefits under Section IV of the Plan, being hereinafter referred to as the "Total Payments"), would be subject (in whole or in part) to the excise tax imposed by Section 4999 of the Code (the "Excise Tax"), then the Total Payments shall be reduced (in the order provided in subsection B below) to the minimum extent necessary to avoid the imposition of the Excise Tax on the Total Payments, but only if (i) the net amount of such Total Payments, as so reduced (and after subtracting the net amount of federal, state and local income and employment taxes on such reduced Total Payments and after taking into account the phase out of itemized deductions and personal exemptions attributable to such reduced Total Payments), is greater than or equal to (ii) the net amount of such Total Payments without such reduction (but after subtracting the net amount of federal, state and local income and employment taxes on such Total Payments and the amount of the Excise Tax to which the Participant would be subject in respect of such unreduced Total Payments and after taking into account the phase out of itemized deductions and personal exemptions attributable to such unreduced Total Payments).

B. The Total Payments shall be reduced in the following order: (i) reduction on a pro-rata basis of any cash severance payments that are exempt from Section 409A, (ii) reduction on a pro-rata basis of any non-cash severance payments or benefits that are exempt from Section 409A, and (iii) reduction of any payments or benefits otherwise payable to the Participant on a pro-rata basis or such other manner that complies with Section 409A; provided, in case of clauses (ii) and (iii), that reduction of any payments attributable to the acceleration of vesting of Company equity awards shall be first applied to Company equity awards that would otherwise vest last in time.

C. All determinations regarding the application of Sections VII.3 shall be made by an accounting firm or consulting group with experience in performing calculations regarding the applicability of Section 280G of the Code and the Excise Tax selected by the Company (the "Independent Advisors"). For purposes of determinations, no portion of the Total Payments shall be taken into account which, in the opinion of the Independent Advisors, (i) does not constitute a "parachute payment" within the meaning of Section 280G(b)(2) of the Code (including by reason of Section 280G(b)(4)(A) of the Code) or (ii) constitutes reasonable compensation for services actually rendered, within the meaning of Section 280G(b)(4)(B) of the Code, in excess of the "base amount" (as defined in Section 280G(b)(3) of the Code) allocable to such reasonable compensation. The costs of obtaining such determination and all related fees and expenses (including related fees and expenses incurred in any later audit) shall be borne by the Company.

In the event it is later determined that a greater reduction in the Total Payments should have been made to implement the objective and intent of Sections VII.3, the excess amount shall be returned promptly by the Participant to the Company.

VIII. DURATION; TERMINATION; AMENDMENT; MODIFICATION

This Plan will become effective on the Effective Date. The Board or the Administrator may amend, modify or terminate this Plan at any time; provided that, except as otherwise provided in Section VII:

A. No amendment, modification or termination may affect any right of any Participant to claim benefits under this Plan as in effect prior to such amendment, modification or termination with respect to a Termination Date that occurs prior to the date of such amendment, modification or termination; and

B. During the CIC Protection Period for a given Participant, this Plan may not be amended or modified in any manner that decreases the payments or benefits payable to the Participant or otherwise adversely affects the Participant's economic rights or terminated.

IX. RELATION TO OTHER PLANS

Nothing in this Plan will prevent or limit a Participant's continuing or future participation in any plan, practice, policy or program provided by the Company or any Affiliate thereof for which the Participant may qualify, nor will anything in this Plan limit or otherwise affect any rights the Participant may have under any contract or agreement with the Company or any Affiliate thereof. Vested benefits and other amounts a Participant is otherwise entitled to receive under any incentive compensation (including any equity award agreement), deferred compensation, retirement, pension or other plan, practice, policy or program of, or any contract or agreement with, the Company or any Affiliate thereof shall be payable in accordance with the terms of each such plan, practice, policy, program, contract or agreement, as the case may be.

X. NOTICES

All notices or other communications required or permitted by this Plan will be made in writing and all such notices or communications will be deemed to have been duly given when delivered or (unless otherwise specified) mailed by United States certified or registered mail, return receipt requested, postage prepaid, addressed as follows:

If to the Company:	Centennial Resource Development, Inc. 1001 17th Street, Suite 1800 Denver, Colorado 80202 Attention: General Counsel
If to the Participant:	The Participant's last known address as set forth in the Company's records.

XI. ADMINISTRATION

The Plan will be interpreted in accordance with its terms and their intended meanings. However, the Administrator will have the discretion to interpret or construe ambiguous, unclear, or implied (but omitted) terms in any fashion the Administrator determines to be appropriate in its reasonable discretion, and to make any findings of fact needed in the administration of the Plan. If, due to errors in drafting, any Plan provision does not accurately reflect its intended meaning, as demonstrated by consistent interpretations or other evidence of intent, or as determined by the Administrator in its reasonable discretion, the provision shall be considered ambiguous and shall be interpreted by the Administrator in a manner consistent with its intent, as determined in the reasonable discretion of the Administrator. The Administrator may amend the Plan retroactively to cure any such ambiguity.

* * * * *

Schedule A

Employment Level	CIC Protection Period	CIC Severance Multiplier	CIC Severance Period	Outplacement Services Period
Chief Executive Officer	24 months following a Change in Control	2.75	24 months following the Termination Date	1 year following the Termination Date
C-suite executive (other than CEO) or Vice President and General Counsel	24 months following a Change in Control	2.25	24 months following the Termination Date	1 year following the Termination Date
Vice President	24 months following a Change in Control	1.5	12 months following the Termination Date	6 months following the Termination Date
All Other Participants	12 months following a Change in Control	1.25	12 months following the Termination Date	3 months following the Termination Date

EXHIBIT 31.1

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

I, Mark G. Papa, certify that:

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

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

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

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

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

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

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

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

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

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

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

Date: November 4, 2019

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

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

EXHIBIT 31.2

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

I, George S. Glyphis, certify that:

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

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

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

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

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

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

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

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

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

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

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

Date: November 4, 2019

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q for the quarter endedSeptember 30, 2019 of Centennial Resource Development, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark G. Papa, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 4, 2019

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

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

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q for the quarter endedSeptember 30, 2019 of Centennial Resource Development, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, George S. Glyphis, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 4, 2019

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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