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 June 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 July 29, 2019, there were 264,436,351 shares of Class A Common Stock, par value $0.0001 per share and 12,003,183 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)

	June 30, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 28,444	$ 18,157
Accounts receivable, net	121,546	100,623
Derivative instruments	174	1,632
Prepaid and other current assets	9,848	9,777
Total current assets	160,012	130,189
Property and Equipment		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,574,668	1,680,065
Proved properties	3,435,804	2,895,280
Accumulated depreciation, depletion and amortization	(698,526)	(496,900)
Total oil and natural gas properties, net	4,311,946	4,078,445
Other property and equipment, net	11,580	8,837
Total property and equipment, net	4,323,526	4,087,282
Noncurrent assets		
Operating lease right-of-use assets	23,161	—
Other noncurrent assets	28,628	42,550
TOTAL ASSETS	$ 4,535,327	$ 4,260,021
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 267,437	$ 240,575
Derivative instruments	14,347	6,051
Operating lease liabilities	18,875	—
Other current liabilities	924	1,090
Total current liabilities	301,583	247,716
Noncurrent liabilities		
Long-term debt, net	881,353	691,630
Asset retirement obligations	14,113	13,895
Deferred income taxes	65,832	62,167
Operating lease liabilities	5,203	—
Other long-term liabilities	—	744
Total liabilities	1,268,084	1,016,152
Commitments and contingencies (Note 10)		
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: 266,254,971 shares issued and 264,431,567 shares outstanding at June 30, 2019 and 265,859,273 shares issued and 264,323,328 shares outstanding at December 31, 2018	27	27
Class C (Convertible): 12,003,183 shares issued and outstanding at June 30, 2019 and December 31, 2018	1	1
Additional paid-in capital	2,846,520	2,833,611
Retained earnings	276,303	266,538
Total shareholders' equity	3,122,851	3,100,177
Noncontrolling interest	144,392	143,692
Total equity	3,267,243	3,243,869
TOTAL LIABILITIES AND EQUITY	$ 4,535,327	$ 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 June 30,		For the Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Operating revenues				
Oil and gas sales	$ 244,239	$ 217,763	$ 458,808	$ 433,661
Operating expenses				
Lease operating expenses	34,885	19,182	64,747	35,458
Severance and ad valorem taxes	17,186	14,208	33,306	28,381
Gathering, processing and transportation expenses	16,243	15,296	31,267	29,124
Depreciation, depletion and amortization	112,114	74,946	208,672	140,956
Impairment and abandonment expense	4,418	1,784	35,682	1,784
Exploration expense	3,861	1,867	6,377	5,314
General and administrative expenses	18,435	13,809	36,553	28,106
Total operating expenses	207,142	141,092	416,604	269,123
Net gain (loss) on sale of long-lived assets	9	(141)	7	(126)
Income from operations	37,106	76,530	42,211	164,412
Other income (expense)				
Interest expense	(14,437)	(5,791)	(24,597)	(11,604)
Net gain (loss) on derivative instruments	2,128	16,697	(3,743)	24,540
Other income (expense)	133	(14)	259	(17)
Total other income (expense)	(12,176)	10,892	(28,081)	12,919
Income before income taxes	24,930	87,422	14,130	177,331
Income tax expense	(5,928)	(19,940)	(3,665)	(39,077)
Net income	19,002	67,482	10,465	138,254
Less: Net income attributable to noncontrolling interest	1,125	3,941	700	8,623
Net income attributable to Class A Common Stock	$ 17,877	$ 63,541	$ 9,765	$ 129,631
Income per share of Class A Common Stock:				
Basic	$ 0.07	$ 0.24	$ 0.04	$ 0.49
Diluted	$ 0.07	$ 0.24	$ 0.04	$ 0.49

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 Six Months Ended June 30,	
	2019	2018
Cash flows from operating activities:		
Net income	$ 10,465	$ 138,254
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	208,672	140,956
Stock-based compensation expense	13,241	8,988
Impairment and abandonment expense	35,682	1,784
Exploratory dry hole costs	—	395
Deferred tax expense	3,665	39,077
Net (gain) loss on sale of long-lived assets	(7)	126
Non-cash portion of derivative (gain) loss	9,754	(19,016)
Amortization of debt issuance costs and discount	1,287	806
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(22,751)	(16,687)
(Increase) decrease in prepaid and other assets	(154)	294
Increase (decrease) in accounts payable and other liabilities	20,340	28,925
Net cash provided by operating activities	280,194	323,902
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(42,264)	(107,193)
Drilling and development capital expenditures	(437,912)	(469,004)
Purchases of other property and equipment	(4,263)	(3,264)
Proceeds from sales of oil and natural gas properties	25,919	146,090
Net cash used in investing activities	(458,520)	(433,371)
Cash flows from financing activities:		
Proceeds from borrowings under revolving credit facility	155,000	115,000
Repayment of borrowings under revolving credit facility	(455,000)	(85,000)
Proceeds from issuance of 2027 Senior Notes	496,175	—
Debt issuance costs	(7,200)	(4,044)
Proceeds from stock options exercised	—	575
Restricted stock used for tax withholdings	(332)	(257)
Net cash provided by financing activities	188,643	26,274
Net increase (decrease) in cash, cash equivalents and restricted cash	10,317	(83,195)
Cash, cash equivalents and restricted cash, beginning of period	21,422	125,915
Cash, cash equivalents and restricted cash, end of period	$ 31,739	$ 42,720

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)

Supplemental cash flow information and non-cash activity:

	For the Six Months Ended June 30,	
	2019	2018
Supplemental cash flow information		
Cash paid for interest	$ 15,799	$ 1,157
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	11,487	—
Investing cash flows from operating leases	9,906	—
Supplemental non-cash activity		
Accrued capital expenditures included in accounts payable and accrued expenses	$ 128,807	$ 97,711
Asset retirement obligations incurred, including revisions to estimates	714	659
Right-of-use assets obtained in exchange for operating lease liabilities	35,267	—

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

	For the Six Months Ended June 30,	
	2019	2018
Cash and cash equivalents	$ 28,444	$ 42,720
Restricted cash[1]	3,295	—
Total cash, cash equivalents and restricted cash	$ 31,739	$ 42,720

(1) Included in *Prepaid and other current assets* line item 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						
	Shares	Amount	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings	Total Shareholder's Equity	Non-controlling Interest	Total Equity
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

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)
Option exercises	10	—	—	—	—	—	164	—	164	—	164
Stock-based compensation	—	—	—	—	—	—	4,333	—	4,333	—	4,333
Conversion of common shares 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)
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

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. All of the Company's assets are concentrated exclusively in the Delaware Basin, a sub-basin of the Permian Basin, and its properties consist of large, contiguous acreage blocks primarily in Reeves County in West Texas and Lea County in 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 is presented as a component of equity. As of June 30, 2019 and December 31, 2018, the noncontrolling interest ownership of CRP was 4.3%.

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) depreciation, depletion and amortization; (iv) asset retirement obligations; (v) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (vi) accrued revenues and related receivables; (vii) accrued liabilities; (viii) valuation of derivatives; and (ix) 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, more historical trend data becomes available, additional information becomes known or as the tax environment changes.

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Recently Issued 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, the effective date, and elected to recognize a cumulative-effect adjustment at the time of adoption. The Company has elected the following practical expedients that allows an entity to carry forward historical accounting treatment relating to (i) lease identification and classification for existing leases upon adoption 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 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 12—Leases* for additional information.

Note 2—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	June 30, 2019	December 31, 2018
Accrued oil and gas sales receivable, net	$ 68,737	$ 66,997
Joint interest billings, net	52,686	31,658
Other	123	1,968
Accounts receivable, net	$ 121,546	$ 100,623

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	June 30, 2019	December 31, 2018
Accounts payable	$ 54,656	$ 55,984
Accrued capital expenditures	90,917	75,791
Revenues payable	80,671	63,399
Accrued interest	20,813	11,129
Accrued employee compensation and benefits	6,840	9,757
Accrued expenses and other	13,540	24,515
Accounts payable and accrued expenses	$ 267,437	$ 240,575

Note 3—Long-Term Debt

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

(in thousands)	June 30, 2019	December 31, 2018
Credit Facility due 2023	$ —	$ 300,000
5.375% Senior Notes due 2026	400,000	400,000
6.875% Senior Notes due 2027	500,000	—
Unamortized debt discount	(3,735)	—
Unamortized debt issuance costs on Senior Notes	(14,912)	(8,370)
Senior Notes, net	881,353	391,630
Total long-term debt, net	$ 881,353	$ 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 June 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 June 30, 2019, the Company had no borrowings outstanding and $799.2 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.

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 June 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; and (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 June 30, 2019, depending on the percentage of the borrowing base utilized. CRP also pays a commitment fee on unused amounts under its facility of a range of 37.5 to 50 basis points. 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.

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 June 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 such series of Senior Notes issued under the indenture governing such series 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 contains 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 June 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 six months ended June 30, 2019:

(in thousands)		
Asset retirement obligations as of January 1, 2019	$	13,895
Liabilities acquired		80
Liabilities incurred		714
Liabilities divested and settled		(1,014)
Accretion expense		438
Asset retirement obligations as of June 30, 2019	$	14,113

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

Long Term Incentive Plan

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 of June 30, 2019, the Company had 8,907,729 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 expense amounts in the table below may not be representative of future expense amounts to be recognized as the value of future awards may vary from historical award amounts. 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 June 30,				For the Six Months Ended June 30,			
(in thousands)	2019		2018		2019		2018	
Restricted stock awards	$	3,408	$	1,989	$	6,590	$	3,764
Stock option awards		2,625		2,310		5,209		4,516
Performance stock units		725		356		1,442		708
Total stock-based compensation expense	$	6,758	$	4,655	$	13,241	$	8,988

Restricted Stock

The following table provides information about restricted stock activity during the six months ended June 30, 2019:

	Awards	Weighted Average Grant Date Fair Value	
Unvested balance as of December 31, 2018	1,535,945	$	17.88
Granted	440,143		12.48
Vested	(137,031)		18.57
Forfeited	(15,652)		16.97
Unvested balance as of June 30, 2019	1,823,405		16.53

The Company grants service-based restricted stock awards to executive officers and employees, which vest ratably over a three-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 $12.48 and $18.87 per share for the six months ended June 30, 2019 and 2018, respectively. The total fair value of restricted stock awards that vested during the six months ended June 30, 2019 and 2018 was $1.5 million and $1.4 million, respectively. Unrecognized compensation cost related to restricted shares that were unvested as of June 30, 2019 was $20.8 million, which the Company expects to recognize over a weighted average period of 1.9 years.

Stock Options

Stock options that have been granted under the LTIP expire ten 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 of three 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 the six months ended June 30, 2019 and 2018:

	For the Six Months Ended June 30,	
	2019	2018
Weighted average grant-date fair value per share	$ 4.77	$ 7.82
Expected term (in years)	6	6
Expected stock volatility	46%	41%
Dividend yield	—%	—%
Risk-free interest rate	2.4%	2.5%

The following table provides information about stock option awards outstanding during the six months ended June 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	244,000	10.23		
Exercised	—	—		
Forfeited	(33,835)	15.79		
Expired	(3,666)	18.23		
Outstanding as of June 30, 2019	4,765,833	16.23	7.8	$ —
Exercisable as of June 30, 2019	2,625,457	16.13	7.5	$ —

The total fair value of stock options that vested during the six months ended June 30, 2019 and 2018 was $4.1 million and $3.7 million, respectively. The intrinsic value of stock options exercised was approximately $0.2 million for the six months ended June 30, 2018 and there were no stock options exercised for the six months ended June 30, 2019. As of June 30, 2019, there was $8.7 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 1.4 years.

Performance Stock Units

During the six months ended June 30, 2019 and 2018, there was no significant performance stock units activity. As of June 30, 2019, there was $4.4 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 1.7 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 flow 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 of June 30, 2019:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl)[1]
Crude oil basis swaps	July 2019 - September 2019	1,380,000	15,000	$ (9.03)
	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	July 2019 - December 2019	5,520,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	July 2019 - December 2019	2,760,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu)[2]
Natural gas basis swaps	July 2019 - December 2019	6,440,000	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.

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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 June 30,		For the Six Months Ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Net gain (loss) on derivative instruments	$ 2,128	$ 16,697	$ (3,743)	$ 24,540

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:

(in thousands)	Balance Sheet Classification	Gross Fair Value Asset/Liability Amounts	Gross Amounts Offset[1]	Net Recognized Fair Value Assets/Liabilities
		June 30, 2019		
Derivative Assets				
Commodity contracts	Current assets - Derivative instruments	$ 5,146	$ (4,972)	$ 174
Derivative Liabilities				
Commodity contracts	Current liabilities - Derivative instruments	19,319	(4,972)	14,347
		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
June 30, 2019			
Total assets	$ —	$ 174	$ —
Total liabilities	—	14,347	—
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.

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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 June 30, 2019 and December 31, 2018:

	June 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair value
Credit facility due 2023[(1)]	$ —	$ —	$ 300,000	$ 300,000
5.375% Senior Notes due 2026[(2)]	392,119	382,000	391,630	372,000
6.875% Senior Notes due 2027[(2)]	489,234	505,000	—	—

(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—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 stock outstanding for the period:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands, except per share data)	**2019**	**2018**	**2019**	**2018**
Net income attributable to Class A Common Stock	$ 17,877	$ 63,541	$ 9,765	$ 129,631
Add: Income from conversion of Class C Common Stock	735	—	442	—
Adjusted net income attributable to Class A Common Stock	$ 18,612	$ 63,541	$ 10,207	$ 129,631
Basic net earnings per share of Class A Common Stock	$ 0.07	$ 0.24	$ 0.04	$ 0.49
Diluted net earnings per share of Class A Common Stock	$ 0.07	$ 0.24	$ 0.04	$ 0.49
Basic weighted average shares of Class A Common Stock outstanding	264,378	263,757	264,397	262,547
Add: Dilutive effect of potential common shares	14	3,249	15	3,554
Add: Dilutive effects of conversion of Class C Common Stock	12,003	—	12,003	—
Diluted weighted average shares of Class A Common Stock outstanding	276,395	267,006	276,415	266,101

For the three and six months ended June 30, 2019 and 2018, the following shares were excluded from the diluted earnings per share calculation as their impacts were anti-dilutive:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Out-of-the-money stock options	4,667	643	4,612	407
Warrants	8,000	—	8,000	—
Restricted stock	1,758	—	1,629	—
Weighted average shares of Class C Common Stock	—	12,314	—	13,497
Performance stock units	—	155	—	77

Note 9—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. For the three and six months ended June 30, 2019, the Company recognized revenues net of processing fees from this marketing agreement amounting to $0.8 million and $1.0 million, respectively, and $0.2 million and $0.3 million for the three and six months ended June 30, 2018, respectively. These revenues are recognized within *Oil and gas sales* and the associated processing fees are recognized within *Gathering, processing and transportation expenses* in the Consolidated Statements of Operations. Included in *Accounts Receivable, net* was $0.9 million and $0.7 million in receivables due from Lucid as of June 30, 2019 and December 31, 2018, respectively.

Note 10—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 six months ended June 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 11—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 June 30,		For the Six Months Ended June 30,	
	2019	2018	2019	2018
Operating revenues (in thousands):				
Oil sales	$ 214,305	$ 174,156	$ 389,859	$ 348,997
Natural gas sales	8,088	13,721	20,585	32,301
NGL sales	21,846	29,886	48,364	52,363
Oil and gas sales	$ 244,239	$ 217,763	$ 458,808	$ 433,661

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 certain 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 natural gas and remits proceeds to Centennial for the resulting sales of NGLs and residue gas. 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, rather than as a net reduction to natural gas and NGL sales.

In the Company’s other natural gas processing agreements, it has the election to take its residue gas “in-kind” at the tailgate of the midstream processing plant and then subsequently market the product. For these contracts, the Company recognizes revenue when control transfers to purchasers at delivery points downstream of the processing plant. The gathering, processing and compression fees are presented as GP&T, and 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 certain 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 June 30, 2019 and December 31, 2018, such receivable balances were $68.7 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 six months ended June 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 12—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 June 30, 2019, these leases have remaining lease terms ranging from one month 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.

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 June 30, 2019
Weighted-average discount rate	4.45%
Weighted-average remaining lease term (years)	1.26

The Company's drilling rig contracts, office rental agreements, and wellhead equipment 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 June 30, 2019	For the Six Months Ended June 30, 2019
Lease costs[(1)]		
Operating lease cost	$ 10,806	$ 21,393
Variable lease cost	703	1,504
Short-term lease cost	16,684	28,908
Total Lease Cost	$ 28,193	$ 51,805

(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 of June 30, 2019 are as follows:

(in thousands)		**Total**
2019[1][2]	$	12,948
2020		8,713
2021		2,855
2022		425
Total lease payments		24,941
Less: imputed interest		(863)
Present value of lease liabilities [3]	$	24,078

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(1) Excludes payments made during the six months ended June 30, 2019.

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

(3) Of the total present value of lease liabilities, $18.9 million was recorded to current *Operating lease liabilities* and $5.2 million was recorded in noncurrent *Operating lease liabilities* in the Consolidated Balance Sheets as of June 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

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. (the "Company," "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 concentrated entirely 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, during the fourth quarter of 2018, WTI spot prices for crude oil significantly declined to a low of $44.48 per barrel, reached a high of $66.30 per barrel in the second quarter of 2019, but the average price remained below $60 per barrel during the first half 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
Crude oil (per Bbl)	$ 51.82	$ 48.32	$ 48.17	$ 55.31	$ 62.91	$ 68.07	$ 69.50	$ 58.81	$ 54.90	$ 59.81
Natural gas (per MMBtu)	$ 3.06	$ 3.14	$ 2.95	$ 2.91	$ 3.08	$ 2.85	$ 2.93	$ 3.77	$ 2.88	$ 2.51

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 a six-rig drilling program during the first half of 2019 which enabled us to complete and bring online 40 gross operated wells. The total number of completed wells during the first half of 2019 had an average effective lateral length of approximately 7,900 feet.

Financing Highlights

In connection with the spring 2019 semi-annual credit facility redetermination, 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.

Results of Operations

Three Months Ended June 30, 2019 Compared to Three Months Ended June 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 June 30,		Increase/(Decrease)	
	2019	2018	$	%
Net revenues (in thousands):				
Oil sales	$ 214,305	$ 174,156	$ 40,149	23 %
Natural gas sales	8,088	13,721	(5,633)	(41)%
NGL sales	21,846	29,886	(8,040)	(27)%
Oil and gas sales	$ 244,239	$ 217,763	$ 26,476	12 %
Average sales prices:				
Oil (per Bbl)	$ 54.63	$ 61.21	$ (6.58)	(11)%
Effect of derivative settlements on average price (per Bbl)	(0.18)	1.69	(1.87)	(111)%
Oil net of hedging (per Bbl)	$ 54.45	$ 62.90	$ (8.45)	(13)%
Average NYMEX price for oil (per Bbl)	$ 59.81	$ 68.07	$ (8.26)	(12)%
Oil differential from NYMEX	(5.18)	(6.86)	1.68	24 %
Natural gas (per Mcf)	$ 0.81	$ 1.81	$ (1.00)	(55)%
Effect of derivative settlements on average price (per Mcf)	0.71	0.05	0.66	1,320 %
Natural gas net of hedging (per Mcf)	$ 1.52	$ 1.86	$ (0.34)	(18)%
Average NYMEX price for natural gas (per Mcf)	$ 2.51	$ 2.85	$ (0.34)	(12)%
Natural gas differential from NYMEX	(1.70)	(1.04)	(0.66)	(63)%
NGL (per Bbl)	$ 16.24	$ 26.52	$ (10.28)	(39)%
Net production:				
Oil (MBbls)	3,922	2,845	1,077	38 %
Natural gas (MMcf)	9,954	7,572	2,382	31 %
NGL (MBbls)	1,346	1,127	219	19 %
Total (MBoe)(1)	6,927	5,235	1,692	32 %
Average daily net production volume:				
Oil (Bbls/d)	43,105	31,271	11,834	38 %
Natural gas (Mcf/d)	109,392	83,205	26,187	31 %
NGL (Bbls/d)	14,785	12,389	2,396	19 %
Total (Boe/d)(1)	76,122	57,528	18,594	32 %

(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 June 30, 2019 were $26.5 million (or 12%) higher than total net revenues for the three months ended June 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 38%, 31% and 19%, respectively, between periods. The oil volume increase resulted primarily from our drilling activities in the Delaware Basin. Since the second quarter 2018, we placed 84 gross operated wells on production in the Delaware Basin, which added 2,320 MBbls of net oil production to the second quarter of 2019. These oil volume increases were offset by normal field production declines across our existing wells. Natural gas and NGLs are produced concurrently with our crude oil volumes, 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 31% and NGL production increased 19% during the second quarter of 2019 compared to the same prior year period.

The increases in production volumes between periods were partially offset by lower average realized sales prices for oil, natural gas and NGLs in the second quarter of 2019 compared to the same 2018 period. The average price for oil before the effects of hedging decreased 11%, the average price for natural gas before effects of hedging decreased 55% and the average price for NGLs decreased 39% between periods. The 11% decrease in the average realized oil price was mainly the result of lower NYMEX crude prices between periods (average NYMEX prices decreased 12%), which were partially offset by improved oil differentials (a decrease of $1.68 per Bbl) in the second quarter of 2019. The average realized sales price of natural gas between periods decreased 55% due to lower average NYMEX gas prices between periods (average NYMEX prices decreased 12%) and wider gas differentials (an increase of $0.66 per Mcf). The continued widening of natural gas price differentials was due to pipeline takeaway capacity constraints impacting the Permian Basin, which has in turn depressed natural gas prices in West Texas. New pipelines are planned to be placed into service beginning in the second half of 2019 continuing through 2021, which are expected to provide relief from these wider gas differentials. The overall 39% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products in the second quarter 2019 as compared to the second quarter of 2018.

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

	For the Three Months Ended June 30,		Increase/(Decrease)	
	2019	2018	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 34,885	$ 19,182	$ 15,703	82 %
Severance and ad valorem taxes	17,186	14,208	2,978	21 %
Gathering, processing and transportation expenses	16,243	15,296	947	6 %
Operating costs per Boe:				
Lease operating expenses	$ 5.04	$ 3.66	$ 1.38	38 %
Severance and ad valorem taxes	2.48	2.71	(0.23)	(8)%
Gathering, processing and transportation expenses	2.34	2.92	(0.58)	(20)%

Lease Operating Expenses. Lease operating expenses ("LOE") for the three months ended June 30, 2019 increased $15.7 million compared to the three months ended June 30, 2018. Higher LOE for the second quarter of 2019 was primarily related to a $9.6 million increase in expense associated with our higher well count. We had 302 gross operated horizontal wells as of June 30, 2019 as compared to 217 gross operated horizontal wells as of June 30, 2018. The net increase in well count was mainly due to our drilling activity adding 84 gross operated wells since the second quarter of 2018, which was further adjusted for acquisitions and divestitures. In addition, workover expense increased $6.1 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 second quarter of 2019 to the same 2018 period. LOE per Boe was $5.04 for the second quarter of 2019, which represents an increase of $1.38 per Boe from the second quarter of 2018. This increase in rate was mainly due to our higher level of workover activity discussed above, as well as (i) higher costs associated with wellhead equipment due to increased monthly rental charges, (ii) increased wellhead chemical and gas mitigation expenses, and (iii) higher field labor costs due to an increase in field employees from June 30, 2018 to June 30, 2019.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the three months ended June 30, 2019 increased $3.0 million compared to the three months ended June 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 increased to 7.0% for three months ended June 30, 2019 as compared to 6.5% for the same period in 2018 due to increased ad valorem taxes of $1.4 million between periods, associated with our higher well count and higher oil and gas reserve values.

Severance and ad valorem taxes decreased on a per Boe basis to $2.48 for the second quarter of 2019 from $2.71 for the second quarter of 2018. This 8% decrease in rate is due to lower average realized sales prices for oil, natural gas and NGLs between periods.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses ("GP&T") for the three months ended June 30, 2019 increased $0.9 million as compared to the three months ended June 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 20% from $2.92 for the second quarter of 2018 to $2.34 per Boe for the second quarter of 2019. On a natural gas and NGL volumes basis (i.e. excluding crude oil barrels) the Boe rate likewise decreased between periods to $5.41 from $6.40 for the three months ended June 30, 2019 and 2018, respectively. This decrease was attributable to the following factors: (i) lower natural gas prices between periods, due to residue gas being a primary cost component of our plant processing fees; and (ii) $2.9 million in reimbursements received from third parties for their usage of our firm transportation capacity in the second quarter of 2019. 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 depreciation, depletion and amortization ("DD&A") for the periods indicated:

	For the Three Months Ended June 30,	
(in thousands, except per Boe data)	**2019**	**2018**
Depreciation, depletion and amortization	$ 112,114	$ 74,946
Depreciation, depletion and amortization per Boe	$ 16.18	$ 14.32

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 June 30, 2019, DD&A expense amounted to $112.1 million, an increase of $37.2 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 $24.5 million of incremental DD&A expense to the second quarter of 2019, while higher DD&A rates between periods contributed an additional $12.7 million of DD&A expense to the second quarter of 2019.

DD&A per Boe was $16.18 for the second quarter of 2019 compared to $14.32 for the same period in 2018. The primary factors contributing to this higher DD&A rate were (i) revisions to proved reserves subsequent to the second 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 June 30, 2019 and 2018, $4.4 million and $1.8 million, respectively, of abandonment expense was incurred related to 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 June 30,	
(in thousands)	**2019**	**2018**
Geological and geophysical costs	$ 3,179	$ 1,204
Stock-based compensation	682	489
Exploratory dry hole costs	—	174
Exploration expense	$ 3,861	$ 1,867

Exploration expense was $3.9 million for the three months ended June 30, 2019 compared to $1.9 million for 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. The period over period increase in exploration expense was primarily due to $1.5 million in higher costs incurred on G&G projects and seismic studies and a $0.7 million increase in G&G personnel expenses due to the average number of geologists increasing between periods.

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

	For the Three Months Ended June 30,	
(in thousands)	**2019**	**2018**
Cash general and administrative expenses	$ 12,359	$ 9,643
Stock-based compensation	6,076	4,166
General and administrative expenses	$ 18,435	$ 13,809

G&A expenses for the three months ended June 30, 2019 were $18.4 million compared to $13.8 million for the second quarter of 2018. Our G&A expenses were higher in 2019 primarily due to $2.0 million in increased employee salaries, wages and payroll burdens, $1.9 million in higher stock-based compensation and $0.8 million in increased software and office rental expenses. These costs were higher during the second quarter of 2019 due to our increase in headcount since June 30, 2018.

Other Income and Expenses.

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

	For the Three Months Ended June 30,	
(in thousands)	**2019**	**2018**
Credit facility	$ 879	$ 687
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	775	427
Interest capitalized	(1,186)	(698)
Total	$ 14,437	$ 5,791

Interest expense was $8.6 million higher for the three months ended June 30, 2019 as compared to the three months ended June 30, 2018 primarily due to interest incurred in the second quarter of 2019 on our 2027 Senior Notes that were issued in March of 2019.

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 underlying commodity prices 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:

	For the Three Months Ended June 30,	
(in thousands)	**2019**	**2018**
Cash settlement gains (losses)	$ 6,388	$ 5,163
Non-cash mark-to-market derivative gain (loss)	(4,260)	11,534
Total	$ 2,128	$ 16,697

Income Tax Expense. We recognized income tax expense of $5.9 million and $19.9 million for the three months ended June 30, 2019 and 2018, respectively. The decrease in income tax expense for the three months ended June 30, 2019 was primarily due to lower pre-tax book income of $62.5 million from the second quarter of 2018 to the second quarter of 2019.

The Company's provision for income taxes for the second quarter of 2019 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.

Six Months Ended June 30, 2019 Compared to Six Months Ended June 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 Six Months Ended June 30,		Increase/(Decrease)	
	2019	2018	$	%
Net revenues (in thousands):				
Oil sales	$ 389,859	$ 348,997	$ 40,862	12 %
Natural gas sales	20,585	32,301	(11,716)	(36)%
NGL sales	48,364	52,363	(3,999)	(8)%
Oil and gas sales	$ 458,808	$ 433,661	$ 25,147	6 %
Average sales prices:				
Oil (per Bbl)	$ 51.51	$ 61.37	$ (9.86)	(16)%
Effect of derivative settlements on average price (per Bbl)	(0.20)	0.89	(1.09)	(122)%
Oil net of hedging (per Bbl)	$ 51.31	$ 62.26	$ (10.95)	(18)%
Average NYMEX price for oil (per Bbl)	$ 57.36	$ 65.55	$ (8.19)	(12)%
Oil differential from NYMEX	(5.85)	(4.18)	(1.67)	(40)%
Natural gas (per Mcf)	$ 1.09	$ 2.12	$ (1.03)	(49)%
Effect of derivative settlements on average price (per Mcf)	0.40	0.03	0.37	1,233 %
Natural gas net of hedging (per Mcf)	$ 1.49	$ 2.15	$ (0.66)	(31)%
Average NYMEX price for natural gas (per Mcf)	$ 2.69	$ 2.96	$ (0.27)	(9)%
Natural gas differential from NYMEX	(1.60)	(0.84)	(0.76)	(90)%
NGL (per Bbl)	$ 17.99	$ 27.99	$ (10.00)	(36)%
Net production:				
Oil (MBbls)	7,568	5,687	1,881	33 %
Natural gas (MMcf)	18,918	15,255	3,663	24 %
NGLs (MBbls)	2,689	1,871	818	44 %
Total (MBoe)[1]	13,410	10,101	3,309	33 %
Average daily net production volume:				
Oil (Bbls/d)	41,814	31,421	10,393	33 %
Natural gas (Mcf/d)	104,521	84,283	20,238	24 %
NGLs (Bbls/d)	14,856	10,340	4,516	44 %
Total (Boe/d)[1]	74,089	55,808	18,281	33 %

(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 six months ended June 30, 2019 were $25.1 million, or 6%, higher than total net revenues for the six months ended June 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 33%, 24% and 44%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin. Since the second quarter 2018, 84 gross operated wells were placed on production in the Delaware Basin, which added 4,177 MBbls of net oil production to the first six 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, resulting in a high correlation between fluctuations in oil quantities sold and natural gas and NGL quantities sold. However, during the second quarter of 2018, the main processor of our wet gas switched from ethane-rejection to ethane-recovery due to lower gas prices in the Permian Basin and higher ethane prices, which led to stronger ethane processing economics. This switch enabled us to recover an increased amount of ethane from our wet gas resulting in a significant increase in NGL volumes between periods (up 44%) compared to a 24% increase in natural gas volumes between periods.

The above increases in production volumes between periods were partially offset by lower average realized sales prices for oil, natural gas and NGLs in the first half of 2019 compared to the same 2018 period. The average price for oil before the effects of hedging decreased 16%, the average price for natural gas before the effects of hedging decreased 49% and the average price for NGLs decreased 36% between periods. The 16% decrease in the average realized oil price was the result of lower NYMEX crude prices between periods (average NYMEX oil prices decreased 12%) and wider oil differentials (an increase of $1.67 per Bbl) in the first half of 2019. Similarly, the 49% decrease in the average realized sales price of natural gas between periods was due to lower average NYMEX gas prices between periods (average NYMEX prices decreased 9%) and wider gas differentials (an increase of $0.76 per Mcf). The overall 36% decrease in average realized NGL prices between periods was primarily attributable to lower Mont Belvieu spot prices for plant products. Both our oil and gas differentials widened during the first half of 2019 as compared to the first half of 2018 due to pipeline takeaway capacity constraints impacting the Permian Basin. New pipelines are planned to be placed into service beginning in the second half of 2019 continuing through 2021, which are expected to provide relief from these wider oil and gas differentials.

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

	For the Six Months Ended June 30,		Increase/(Decrease)	
	2019	2018	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 64,747	$ 35,458	$ 29,289	83 %
Severance and ad valorem taxes	33,306	28,381	4,925	17 %
Gathering, processing and transportation expenses	31,267	29,124	2,143	7 %
Operating costs per Boe:				
Lease operating expenses	$ 4.83	$ 3.51	$ 1.32	38 %
Severance and ad valorem taxes	2.48	2.81	(0.33)	(12)%
Gathering, processing and transportation expenses	2.33	2.88	(0.55)	(19)%

Lease Operating Expenses. LOE for the six months ended June 30, 2019 increased $29.3 million as compared to the six months ended June 30, 2018. Higher LOE for the first half of 2019 was primarily related to a $16.2 million increase in expense associated with our higher well count, as well as increased water production which resulted in higher water disposal costs. We had 302 gross operated horizontal wells as of June 30, 2019 compared to 217 gross operated horizontal wells as of June 30, 2018. The net increase in well count was mainly the result of our drilling activity adding 84 gross operated wells since the second quarter of 2018, was further adjusted for acquisitions and divestitures. In addition, workover activity increased $13.1 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 half of 2019 to the same 2018 period. LOE per Boe was $4.83 for the six months ended June 30, 2019, which represents an increase of $1.32 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) higher costs associated with wellhead equipment due to increased monthly rental charges, (ii) increased wellhead chemicals and gas mitigation expenses, and (iii) higher field labor costs due to an increase in field employees from June 30, 2018 to June 30, 2019.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes for the six months ended June 30, 2019 increased $4.9 million compared to the six months ended June 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 7.2% for the six months ended June 30, 2019 as compared to 6.6% in 2018 due to increased ad valorem taxes of $3.2 million between periods, associated with our higher well count and higher oil and gas reserve values.

Severance and ad valorem taxes decreased on a per Boe basis to $2.48 for the six months ended June 30, 2019 from $2.81 for the six months ended June 30, 2018. This 12% 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 six months ended June 30, 2019 increased $2.1 million compared to the six months ended June 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 19% from $2.88 in the first half of 2018 to $2.33 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 $5.35 from $6.60 for the six months ended June 30, 2019 and 2018, respectively. This decrease was attributable to the following factors: (i) lower natural gas prices between periods, due to residue gas being a primary cost component of gas processing fees; and (ii) $10.4 million in reimbursements received from third parties for their usage of our firm transportation capacity in the first half of 2019. 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 Six Months Ended June 30,	
(in thousands, except per Boe data)	**2019**	**2018**
Depreciation, depletion and amortization	$ 208,672	$ 140,956
Depreciation, depletion and amortization per Boe	$ 15.56	$ 13.95

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 six months ended June 30, 2019, DD&A expense amounted to $208.7 million, an increase of $67.7 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 $46.4 million of incremental DD&A expense during the first six months of 2019, while higher DD&A rates between periods contributed an additional $21.3 million of DD&A expense to the first six months of 2019.

DD&A per Boe was $15.56 for the first half of 2019 compared to $13.95 for the same period in 2018. The primary factors contributing to this higher DD&A rate were (i) revisions to proved reserves subsequent to the second quarter of 2018, and (ii) a higher level of infrastructure costs (having no associated proved reserve adds).

Impairment and Abandonment Expenses. During the six months ended June 30, 2019, $35.7 million of abandonment expense was incurred related to undeveloped leasehold acreage. Of this amount, $19.1 million was incurred with respect to non-core acreage that expired during the first half of 2019 after efforts to extend, sell or trade these leases were unsuccessful, and $16.6 million was identified as impaired acreage based on impairment indicators that arose during the period, following an acreage sale that was initiated in the first quarter of 2019.

During the six months ended June 30, 2018, $1.8 million of abandonment expense was incurred related to undeveloped leasehold acreage that expired during the period.

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

	For the Six Months Ended June 30,	
(in thousands)	**2019**	**2018**
Geological and geophysical costs	$ 5,095	$ 4,049
Stock-based compensation	1,282	870
Exploratory dry hole costs	—	395
Exploration expense	$ 6,377	$ 5,314

Exploration was $6.4 million for the six months ended June 30, 2019 compared to $5.3 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 $1.7 million during the first half 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 Six Months Ended June 30,	
(in thousands)	**2019**	**2018**
Cash general and administrative expenses	$ 24,594	$ 19,988
Stock-based compensation	11,959	8,118
General and administrative expenses	$ 36,553	$ 28,106

G&A expenses for the six months ended June 30, 2019 were $36.6 million compared to $28.1 million for the six months ended June 30, 2018. The higher G&A expenses incurred in 2019 were primarily due to $4.5 million in increased employee salaries, wages and payroll burdens, $3.8 million in higher stock-based compensation and $1.2 million in increased software and office rental expenses. These costs were higher during the first half of 2019 due to our increase in headcount since June 30, 2018. These increases were partially offset by $0.9 million lower professional fees incurred during the six months ended June 30, 2019 as compared to the prior year period.

Other Income and Expenses.

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

	For the Six Months Ended June 30,	
(in thousands)	**2019**	**2018**
Credit facility	$ 4,611	$ 1,470
5.375% Senior Notes due 2026	10,750	10,750
6.875% Senior Notes due 2027	10,122	—
Amortization of debt issuance costs and debt discount	1,287	806
Interest capitalized	(2,173)	(1,422)
Total	$ 24,597	$ 11,604

Interest expense was $13.0 million higher for the six months ended June 30, 2019 compared to the same 2018 period primarily due to $10.1 million in interest we incurred in the first half 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 half of 2019. The Company's weighted average borrowings outstanding under our credit facility were $158.0 million and $20.8 million for the first half of 2019 and 2018, respectively. Our credit facility's weighted average effective interest rate was 4.1% for the six months ended June 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 underlying commodity prices 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 Six Months Ended June 30,	
(in thousands)	**2019**	**2018**
Cash settlement gains (losses)	$ 6,011	$ 5,524
Non-cash mark-to-market derivative gain (loss)	(9,754)	19,016
Total	$ (3,743)	$ 24,540

Income Tax Expense. During the six months ended June 30, 2019 and 2018, the Company recognized income tax expense of $3.7 million and $39.1 million, respectively. The decrease in income tax expense for the six months ended June 30, 2019 as compared to the same period in 2018 was primarily due to a decrease in pre-tax income of $163.2 million between periods.

The Company's provision for income taxes for the first half of 2019 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 and 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 the six months ended June 30, 2019:

(in millions)	For the Six Months Ended June 30, 2019
Drilling and completion capital expenditures	$ 368.2
Facilities, infrastructure and other	90.2
Land	24.2
Total capital expenditures	$ 482.6

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 driven by a shift in our rig activity from seven to six rigs and the associated decrease in development capex associated with running a six-rig drilling program.

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 of 2019, 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 and 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:

	For the Six Months Ended June 30,	
(in thousands)	2019	2018
Net cash provided by operating activities	$ 280,194	$ 323,902
Net cash used in investing activities	(458,520)	(433,371)
Net cash provided by financing activities	188,643	26,274

For the six months ended June 30, 2019, we generated $280.2 million of cash from operating activities, a decrease of $43.7 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 expense and the timing of our receivable collections and supplier payments during the six months ended June 30, 2019. These declining factors were partially offset by higher crude oil, natural gas and NGL production volumes and higher cash settlements gains from derivatives for the six months ended June 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 six months ended June 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 $300.0 million under our credit facility, to finance $437.9 million of drilling and development capex, to fund $42.3 million in oil and gas property acquisitions and to purchase $4.3 million of other property and equipment.

During the six months ended June 30, 2018, cash flows from operating activities, cash on hand, proceeds from sales of oil and gas properties, and $30.0 million in net borrowings under our credit facility were used to finance $469.0 million of drilling and development capex and $107.2 million in oil and gas property acquisitions.

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 June 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 June 30, 2019, the Company had no borrowings outstanding and $799.2 million in available borrowing capacity, which was net of $0.8 million in letters of credit outstanding.

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 June 30, 2019 and through the filing of this Quarterly Report.

In connection with the spring 2019 semi-annual credit facility redetermination, 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 (as described above) is less than or equal to 3.0 to 1.0; otherwise, the original applicable margins would be applied.

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 the Company, nor is the Company 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 June 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

The Company's 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 six months ended June 30, 2019 to the critical accounting policies previously disclosed in our 2018 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 half of 2019, our income before income taxes for the six months ended June 30, 2019 would have moved up or down $39.0 million for each 10% change in oil prices per Bbl, $4.8 million for each 10% change in NGL prices per Bbl, and $2.1 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 the Company had in place as of June 30, 2019:

	Period	Volume (Bbls)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl)[1]
Crude oil basis swaps	July 2019 - September 2019	1,380,000	15,000	$ (9.03)
	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 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	July 2019 - December 2019	5,520,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	July 2019 - December 2019	2,760,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu)[2]
Natural gas basis swaps	July 2019 - December 2019	6,440,000	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 June 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		(6,011)
Change in the futures curve of forecasted commodity prices[1]		(3,743)
Net fair value of oil and gas derivative contracts outstanding as of June 30, 2019	$	(14,173)

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[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 June 30, 2019 would cause a $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 June 30, 2019 would cause a $0.9 million increase or decrease, respectively, in this same fair value liability.

Interest Rate Risk

The Company's ability to borrow and the rates offered by lenders can be adversely affected by deteriorations in the credit markets and/or downgrades in the Company's credit rating. CRP's credit facility interest rate is based on a LIBOR spread, which exposes the Company to interest rate risk if we have borrowings outstanding. At June 30, 2019, the Company had no borrowings outstanding under its credit agreement. 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 Company's remaining long-term debt balance of $881.4 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 the Company's 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 June 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 June 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 June 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 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).
4.1	Indenture, dated as of March 15, 2019, by and amount Centennial Resource Production, LLC, the subsidiary guarantors named therein and UMB Bank, N.A. as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with SEC on March 18, 2019).
10.1#	Centennial Resource Development, Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 6, 2019).
10.2*#	Centennial Resource Development, Inc. Second Amended and Restated Non-Employee Director Compensation Program
10.3*#	Form of Performance Restricted Stock Unit Agreement under the Centennial Resource Development, Inc. 2016 Long Term Incentive 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: August 5, 2019

EXHIBIT 10.2

CENTENNIAL RESOURCE DEVELOPMENT, INC.
SECOND AMENDED AND RESTATED
NON-EMPLOYEE DIRECTOR COMPENSATION PROGRAM

Effective Date: July 30, 2019

Each member of the board of directors (the "***Board***") of Centennial Resource Development, Inc. (the "***Company***") who is not an employee of the Company or any parent or subsidiary of the Company and is not affiliated with Riverstone Investment Group LLC or NGP Energy Capital Management, L.L.C. (each, a "***Non-Employee Director***") will receive the compensation in this Amended and Restated Non-Employee Director Compensation Program (this "***Program***") for service as a Non-Employee Director. The compensation described in this Program will be paid or be made, as applicable, automatically and without further action of the Board to each Non-Employee Director who is entitled to receive the compensation, unless the Non-Employee Director declines receipt of the compensation by written notice to the Company. The terms and conditions of this Program will supersede any prior cash or equity compensation arrangements for service as a member of the Board between the Company and any of its Non-Employee Directors. This Program will remain in effect until it is revised or rescinded by further action of the Board. This Program may be amended, modified or terminated by the Board at any time in its sole discretion. No Non-Employee Director will have any rights under this Program.

I. CASH COMPENSATION

A. Annual Retainers. Each Non-Employee Director will receive an annual retainer of $87,500 (the "***Annual Retainer***"). If a Non-Employee Director is also serving as the Lead Director of the Board as contemplated by the Company's Corporate Governance Guidelines, such Non-Employee Director will receive an additional annual retainer of $50,000 as compensation for the additional responsibilities associated with serving as the Lead Director (the "***Lead Director Retainer***" and, together with the Annual Retainer, the "***Retainers***").

B. Payment of Retainers. The Retainers will be earned on a quarterly basis based on a calendar quarter and paid in cash by the Company in arrears not later than the fifteenth day following the end of each calendar quarter. If a Non-Employee Director does not serve as a Non-Employee Director for an entire calendar quarter, or a Non-Employee Director serves as the Lead Director but not for an entire calendar quarter, the Non-Employee Director's Retainer will be prorated for the portion of the calendar quarter actually served as a Non-Employee Director or Lead Director, as applicable.

II. EQUITY COMPENSATION

Non-Employee Directors will be granted the awards of Restricted Stock (as defined in the Company's 2016 Long Term Incentive Plan or any other applicable Company equity incentive plan then-maintained by the Company (the "***Equity Plan***")) described below (each, a "***Restricted Stock Award***"). The Restricted Stock Awards will be granted under and subject to the terms of the Plan and award agreements in substantially the form approved by the Board. All applicable terms of the Equity Plan apply to this Program as if fully set forth herein, and all Restricted Stock Awards under this Program are subject in all respects to the terms of the Equity Plan and the applicable award agreement.

A. Restricted Stock Awards. A Non-Employee Director who is serving as a Non-Employee Director as of the last day of the Company's fiscal year (in each case, an "***Annual Grant Date***") will be automatically granted on each Annual Grant Date a number of shares of Restricted Stock equal to the quotient obtained by dividing (i) the applicable Annual Award Amount (as defined below) by (ii) the average daily closing price of one share of the Company's Common Stock on the NASDAQ Capital Market over the five consecutive trading days ending on the day before the applicable Annual Grant Date. If a Non-Employee Director is first appointed or elected on a date other than an Annual Grant Date, or a member of the Board first becomes a Non-Employee Director as described in clause B below on a date other than an Annual Grant Date (in either case, a "***Mid-Year Grant Date***"), the Non-Employee Director will be automatically granted on the Mid-Year Grant Date a number of shares of Restricted Stock equal to the quotient obtained by dividing (x) the product of the applicable Annual Award Amount and the number of days remaining in the Company's fiscal year following the Mid-Year Grant Date, by (y) the product of 365 and the average daily closing price of one share of the Company's Common Stock on the NASDAQ Capital Market over the five consecutive trading days ending on the day before the Mid-Year Grant Date. Each Annual Grant Date and Mid-Year Grant Date shall be referred to individually as a "***Grant Date***." For each Non-Employee Director, the "***Annual Award Amount***" determined on the applicable Grant Date shall equal (a) $162,500, *plus* (b) $20,000, if the Non-Employee Director is the chair of the Audit Committee of the Board on the Grant Date, *plus* (c) $15,000, if the Non-Employee Director is the chair of the Compensation Committee of the Board on the Grant Date, and *plus* (d) $15,000, if the Non-Employee Director is the chair of the Nominating and Corporate Governance Committee of the Board on the Grant Date.

B. Termination of Employment of Employee Directors. Members of the Board who are employees of the Company or any parent or subsidiary of the Company who subsequently terminate their employment with the Company and any parent or subsidiary of the Company and remain on the Board will, to the extent that they are otherwise eligible, be eligible to receive, Restricted Stock Awards under this Program on Grant Dates occurring on or after their termination of employment with the Company and any parent or subsidiary of the Company.

C . Vesting. Each Restricted Stock Award shall vest in a single installment on the earlier to occur of (i) the first anniversary of the Grant Date and (ii) immediately prior to and contingent upon the closing of a Change in Control (as defined in the Equity Plan), subject in each case to the Non-Employee Director continuing in service as a Non-Employee Director through the vesting date. Unless the Board otherwise determines, any Restricted Stock Award that is unvested at the time of a Non-Employee Director's termination of service on the Board as a Non-Employee Director will be immediately forfeited upon such termination of service and will not thereafter become vested.

III. COMPENSATION LIMITS

Notwithstanding anything to the contrary in this Program, all compensation payable under this Program will be subject to any limits on the maximum amount of Non-Employee Director compensation set forth in the Equity Plan, as in effect from time to time.

* *

EXHIBIT 10.3

CENTENNIAL RESOURCE DEVELOPMENT, INC.
2016 LONG TERM INCENTIVE PLAN

PERFORMANCE RESTRICTED STOCK UNIT GRANT NOTICE

Capitalized terms not specifically defined in this Performance Restricted Stock Unit Grant Notice (the "***Grant Notice***") have the meanings given to them in the 2016 Long Term Incentive Plan (as amended from time to time, the "***Plan***") of Centennial Resource Development, Inc. (the "***Company***").

The Company has granted to the participant listed below ("***Participant***") the Restricted Stock Units described in this Grant Notice (the "***PSUs***"), subject to the terms and conditions of the Plan and the Performance Restricted Stock Unit Agreement attached as **Exhibit A** (the "***Agreement***"), both of which are incorporated into this Grant Notice by reference.

Participant:	[__________]
Grant Date:	July 30, 2019
Performance Period:	July 1, 2019 through June 30, 2022
Target Number of PSUs:	[__________]

By Participant's signature below, Participant agrees to be bound by the terms of this Grant Notice, the Plan and the Agreement. Participant has reviewed the Plan, this Grant Notice and the Agreement in their entirety, has had an opportunity to obtain the advice of counsel prior to executing this Grant Notice and fully understands all provisions of the Plan, this Grant Notice and the Agreement. Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Administrator upon any questions arising under the Plan, this Grant Notice or the Agreement.

CENTENNIAL RESOURCE DEVELOPMENT, INC.		**PARTICIPANT**
By:	______________________	______________________
Name:	______________________	[Participant Name]
Title:	______________________	

PERFORMANCE RESTRICTED STOCK UNIT AGREEMENT

Capitalized terms not specifically defined in this Agreement have the meanings specified in the Grant Notice or, if not defined in the Grant Notice, in the Plan.

ARTICLE I.
GENERAL

1.1 Award of PSUs and Dividend Equivalents.

(a) The Company has granted the PSUs to Participant effective as of the grant date set forth in the Grant Notice (the "***Grant Date***"). Each PSU represents the right to receive one Share or, at the option of the Administrator, an amount of cash, in either case, as set forth in this Agreement. Participant will have no right to the distribution of any Shares or payment of any cash until the time (if ever) the PSUs have vested.

(b) The Company hereby grants to Participant, with respect to each PSU, a Dividend Equivalent for ordinary cash dividends paid to substantially all holders of outstanding Shares with a record date after the Grant Date and prior to the date the applicable PSU is settled, forfeited or otherwise expires. Each Dividend Equivalent entitles Participant to receive the equivalent value of any such ordinary cash dividends paid on a single Share. The Company will establish a separate Dividend Equivalent bookkeeping account (a "***Dividend Equivalent Account***") for each Dividend Equivalent and credit the Dividend Equivalent Account (without interest) on the applicable dividend payment date with the amount of any such cash paid.

1.2 Incorporation of Terms of Plan. The PSUs and Dividend Equivalents are subject to the terms and conditions set forth in this Agreement and the Plan, which is incorporated herein by reference. In the event of any inconsistency between the Plan and this Agreement, the terms of the Plan will control.

1.3 Unsecured Promise. The PSUs and Dividend Equivalents will at all times prior to settlement represent an unsecured Company obligation payable only from the Company's general assets.

ARTICLE II.
VESTING; FORFEITURE AND SETTLEMENT

2.1 Vesting; Forfeiture.

(a) The PSUs will be earned based on the Company's achievement of the performance conditions set forth in Appendix A and, to the extent earned, the PSUs will vest in accordance with the schedule and terms set forth in Section 2.1(b). Any fraction of a PSU that would otherwise be vested will be rounded to the nearest whole PSU. Any PSUs that are not earned in accordance with the performance conditions set forth in Appendix A will immediately and automatically be cancelled and forfeited without consideration as of the date of determination. In the event of Participant's Termination of Service for any reason, all unvested PSUs will immediately and automatically be cancelled and forfeited, except as otherwise determined by the Administrator or provided in a binding written agreement between Participant and the Company. Dividend Equivalents (including any Dividend Equivalent Account balance) will vest or be forfeited, as applicable, upon the vesting or forfeiture of the PSU with respect to which the Dividend Equivalent (including the Dividend Equivalent Account) relates.

(b) The PSUs will be earned, if at all, at a level of between 50% and 200% of the Target Number of PSUs specified in the Grant Notice (the "***Target Number of PSUs***") based on the Company's achievement of the performance conditions set forth in Appendix A for the Performance Period set forth in the Grant Notice (the "***Performance Period***"). When practicable following the completion of the Performance Period, but in no event more than thirty (30) days thereafter, the Administrator shall determine the extent to which the performance conditions set forth in Appendix A have been satisfied (such date of determination, the "***Final Determination Date***"). To the extent earned, the PSUs will vest on the Final Determination Date, subject to Participant not incurring a Termination of Service on or prior to the last day of the Performance Period.

2.2 Settlement.

(a) PSUs and Dividend Equivalents (including any Dividend Equivalent Account balance) will be paid in Shares or cash at the Administrator's option as soon as administratively practicable after the vesting of the applicable PSU, but in no event more than thirty (30) days after the PSU's vesting date. Notwithstanding the foregoing, the Company may delay any payment under this Agreement that the Company reasonably determines would violate Applicable Law until the earliest date the Company reasonably determines the making of the payment will not cause such a violation (in accordance with Treasury Regulation Section 1.409A-2(b)(7)(ii)), provided the Company reasonably believes the delay will not result in the imposition of excise taxes under Section 409A.

(b) If a PSU is paid in cash, the amount of cash paid with respect to the PSU will equal the Fair Market Value of a Share on the fifth business day preceding the payment date. If a Dividend Equivalent is paid in Shares, the number of Shares paid with respect to the Dividend Equivalent will equal the quotient, rounded down to the nearest whole Share, of the Dividend Equivalent Account balance divided by the Fair Market Value of a Share on the fifth business day preceding the payment date.

ARTICLE III.
TAXATION AND TAX WITHHOLDING

3.1 Representation. Participant represents to the Company that Participant has reviewed with Participant's own tax advisors the tax consequences of this Award and the transactions contemplated by the Grant Notice and this Agreement. Participant is relying solely on such advisors and not on any statements or representations of the Company or any of its agents.

3.2 Tax Withholding.

(a) The Company has the right and option, but not the obligation, to treat Participant's failure to provide timely payment in accordance with the Plan of any withholding tax arising in connection with the PSUs or Dividend Equivalents as Participant's election to satisfy all or any portion of the withholding tax by requesting the Company retain Shares otherwise issuable under the Award.

(b) Participant acknowledges that Participant is ultimately liable and responsible for all taxes owed in connection with the PSUs and the Dividend Equivalents, regardless of any action the Company or any Subsidiary takes with respect to any tax withholding obligations that arise in connection with the PSUs or Dividend Equivalents. Neither the Company nor any Subsidiary makes any representation or undertaking regarding the treatment of any tax withholding in connection with the awarding, vesting or payment of the PSUs or the Dividend Equivalents or the subsequent sale of Shares. The Company and the Subsidiaries do not commit and are under no obligation to structure the PSUs or Dividend Equivalents to reduce or eliminate Participant's tax liability.

ARTICLE IV.
OTHER PROVISIONS

4.1 Adjustments. Participant acknowledges that the PSUs, the Shares subject to the PSUs and the Dividend Equivalents are subject to adjustment, modification and termination in certain events as provided in this Agreement and the Plan.

4.2 Notices. Any notice to be given under the terms of this Agreement to the Company must be in writing and addressed to the Company in care of the Company's Secretary at the Company's principal office or the Secretary's then-current email address or facsimile number. Any notice to be given under the terms of this Agreement to Participant must be in writing and addressed to Participant at Participant's last known mailing address, email address or facsimile number in the Company's personnel files. By a notice given pursuant to this Section, either party may designate a different address for notices to be given to that party. Any notice will be deemed duly given when actually received, when sent by email, when sent by certified mail (return receipt requested) and deposited with postage prepaid in a post office or branch post office regularly maintained by the United States Postal Service, when delivered by a nationally recognized express shipping company or upon receipt of a facsimile transmission confirmation.

4.3 Titles. Titles are provided herein for convenience only and are not to serve as a basis for interpretation or construction of this Agreement.

4.4 Conformity to Securities Laws. Participant acknowledges that the Plan, the Grant Notice and this Agreement are intended to conform to the extent necessary with all Applicable Laws and, to the extent Applicable Laws permit, will be deemed amended as necessary to conform to Applicable Laws.

4.5 Successors and Assigns. The Company may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement will inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer set forth in the Plan, this Agreement will be binding upon and inure to the benefit of the heirs, legatees, legal representatives, successors and assigns of the parties hereto.

4.6 Limitations Applicable to Section 16 Persons. Notwithstanding any other provision of the Plan or this Agreement, if Participant is subject to Section 16 of the Exchange Act, the Plan, the Grant Notice, this Agreement, the PSUs and the Dividend Equivalents will be subject to any additional limitations set forth in any applicable exemptive rule under Section 16 of the Exchange Act (including any amendment to Rule 16b-3) that are requirements for the application of such exemptive rule. To the extent Applicable Laws permit, this Agreement will be deemed amended as necessary to conform to such applicable exemptive rule.

4.7 Entire Agreement. The Plan, the Grant Notice and this Agreement (including any exhibit hereto) constitute the entire agreement of the parties and supersede in their entirety all prior undertakings and agreements of the Company and Participant with respect to the subject matter hereof.

4.8 Agreement Severable. In the event that any provision of the Grant Notice or this Agreement is held illegal or invalid, the provision will be severable from, and the illegality or invalidity of the provision will not be construed to have any effect on, the remaining provisions of the Grant Notice or this Agreement.

4.9 Limitation on Participant's Rights. Participation in the Plan confers no rights or interests other than as herein provided. This Agreement creates only a contractual obligation on the part of the Company as to amounts payable and may not be construed as creating a trust. Neither the Plan nor any underlying program, in and of itself, has any assets. Participant will have only the rights of a general unsecured creditor of the Company with respect to amounts credited and benefits payable, if any, with respect to the PSUs and Dividend Equivalents, and rights no greater than the right to receive cash or the Shares as a general unsecured creditor with respect to the PSUs and Dividend Equivalents, as and when settled pursuant to the terms of this Agreement.

4.10 Not a Contract of Employment. Nothing in the Plan, the Grant Notice or this Agreement confers upon Participant any right to continue in the employ or service of the Company or any Subsidiary or interferes with or restricts in any way the rights of the Company and its Subsidiaries, which rights are hereby expressly reserved, to discharge or terminate the services of Participant at any time for any reason whatsoever, with or without Cause, except to the extent expressly provided otherwise in a written agreement between the Company or a Subsidiary and Participant.

4.11 Counterparts. The Grant Notice may be executed in one or more counterparts, including by way of any electronic signature, subject to Applicable Law, each of which will be deemed an original and all of which together will constitute one instrument.

* * * * *

<u>**Appendix A**</u>

Performance Goals
The performance measure for the PSU award is the Company's total shareholder return ("***TSR***") compared to the TSR of a group of peer companies. TSR combines share price appreciation and dividends paid to show the total return to the shareholder. The absolute size of the TSR will vary with the stock market, but the relative position to Company's peers over the Performance Period is the performance metric for this Award.

TSR will be the sum of the Company's ending stock price plus dividends over the Performance Period divided by the Company's beginning stock price. Both the beginning and ending stock prices will be calculated using the average closing price during the last 20 trading days prior to and including the calculation date. This calculation is used instead of the actual closing price on the given date to smooth volatility in the stock price and avoid single-day fluctuations.

$$\text{TSR} = \frac{\text{ending stock price + all dividends with a record date during the Performance Period}}{\text{beginning stock price}}$$

Peer Group
The following companies are included in the Company's peer group for purposes of this Award:

Callon Petroleum Company	Oasis Petroleum Inc.
Cimarex Energy Co.	Parsley Energy, Inc.
Jagged Peak Energy Inc.	PDC Energy, Inc.
Laredo Petroleum, Inc.	SM Energy Company
Matador Resources Company	WPX Energy, Inc.

Should a peer company cease to exist as a separate publicly traded company during the Performance Period due to bankruptcy, it will nonetheless remain as a member of the Company's peer group for purposes of the payout calculation described below and the Company shall be ranked higher than such peer company for purposes of the payout calculation. Should a peer company cease to exist as a separate publicly traded company during the Performance Period due to a merger, acquisition or other similar transaction, it will be considered automatically removed from the peer group list and the number of PSUs earned will be determined based on the Company's percentile rank among the resulting peer group.

Payout Calculation
At the end of the Performance Period, the number of PSUs earned will be determined based on the Company's TSR relative to the Company's peer group over the Performance Period. The Company's TSR is ranked among the peers and the percentile rank is calculated, based on the Company's position in the ranking, as the percentage of members of the peer group (including the Company and as the peer group is constituted on the final day of the Performance Period) with a ranking that is greater than or equal to the Company's ranking (i.e. with a TSR that is less than or equal to the Company's TSR). The payout scale is detailed in the following table.

Relative TSR Performance Plan		
Performance Rank	TSR Percentile Ranking	Payout as % of Target Number of PSUs
1	100%	200%
2	90%	180%
3	80%	160%
4	70%	140%
5	60%	120%
6	50%	100%
7	40%	75%
8	30%	50%
9	20%	0%
10	10%	0%
11	0%	0%

The number of PSUs earned will be determined based on the TSR Percentile Ranking, with linear interpolation between any specified TSR Percentile Ranking set forth in the table above. Notwithstanding the foregoing, if the Company's TSR is less than or equal to zero on an absolute basis, the number of PSUs shall not be greater than 100% of the Target Number of PSUs (i.e., the payout shall not be greater than 100%).

The actual payout of the PSUs, if any, at the end of the Performance Period will be made as provided under the Performance Restricted Stock Unit Agreement to which this Appendix A is attached.

Adjustments for Extraordinary Events
Notwithstanding the foregoing, if the Administrator determines that due to a reduction in the size of the peer group or other unusual, extraordinary or nonrecurring transactions or events materially affecting the Award, an adjustment in the peer group, the payment schedule and/or other terms of the Award is necessary or appropriate to avoid the dilution or enlargement of the benefits or potential benefits intended to be made available under the Award, the Administrator may adjust the peer group (including by removing constituent companies, substituting for existing constituent companies or selecting new constituent companies to replace withdrawn companies), the payment schedule and/or such other terms of the Award in such a manner as the Administrator determines in good faith to be equitable to reflect such transactions or events.

* * * * *

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: August 5, 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: August 5, 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 ended June 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: August 5, 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 ended June 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: August 5, 2019

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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