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, 2018

OR

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

For the transition period from to

Commission file number 001-37697

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)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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 ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐	Emerging growth company ☐

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

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

As of July 31, 2018, there were 263,791,826 shares of Class A Common Stock, par value $0.0001 per share and 12,297,298 shares of Class C Common Stock, par value $0.0001 per share, outstanding.

TABLE OF CONTENTS

		Page
Glossary of Oil and Natural Gas Terms		3
Glossary of Certain Other Terms		5
Cautionary Statement Concerning Forward-Looking Statements		6
Part I—FINANCIAL INFORMATION		8
Item 1.	Financial Statements (Unaudited)	8
	Consolidated Balance Sheets as of June 30, 2018 and December 31, 2017	8
	Consolidated Statements of Operations for the Three and Six Months Ended June 30, 2018 and 2017	9
	Consolidated Statements of Cash Flows for the Three and Six Months Ended June 30, 2018 and 2017	10
	Consolidated Statements of Shareholders' Equity for the Six Months Ended June 30, 2018 and 2017	12
	Notes to Consolidated Financial Statements	13
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	28
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	41
Item 4.	Controls and Procedures	43
Part II—OTHER INFORMATION		44
Item 1.	Legal Proceedings	44
Item 1A.	Risk Factors	44
Item 6.	Exhibits	44
Signatures		45

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.

Bbls/d. Barrels 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.

Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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 in 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.

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.

GMT Acquisition. The acquisition of certain undeveloped acreage and producing oil and natural gas properties of GMT Exploration Company LLC, which closed on June 8, 2017.

IPO. Our initial public offering of units, which closed on February 29, 2016.

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.

Private Placement Warrants. Our 8,000,000 outstanding warrants for the purchase of shares of Class A Common Stock, which were purchased by our Sponsor in a private placement simultaneously with the closing of our IPO.

Public Warrants. Warrants for the purchase of shares of Class A Common Stock sold as part of the Units in our IPO, all of which have been exercised or redeemed and are no longer outstanding.

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

Riverstone Purchasers. Riverstone VI Centennial QB Holdings, L.P., Riverstone Non-ECI USRPI AIV, L.P. and REL US Centennial Holdings, LLC, which are affiliates of Riverstone.

Series B Preferred Stock. Our Series B Preferred Stock, par value $0.0001 per share, all outstanding shares of which were converted into 26,100,000 shares of Class A Common Stock on May 25, 2017.

Silverback. Silverback Exploration, LLC and Silverback Operating, LLC, collectively.

Silverback Acquisition. The acquisition of leasehold interests and related upstream assets in Reeves County, Texas from Silverback, which closed on December 28, 2016.

Units. Our units sold in our IPO, each of which consisted of one share of Class A Common Stock and one-third of one Public Warrant.

V*oting common stock*. Our Class A Common Stock and Class C Common Stock.

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," "believe," "anticipate," "intend," "estimate," "expect," "project" 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, 2017 ("2017 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;
- 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.

All forward-looking statements, expressed or implied, are made only as of the date of this Quarterly Report. 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 2017 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.

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, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 42,720	$ 117,315
Accounts receivable, net	101,553	78,786
Derivative instruments	22,727	433
Prepaid and other current assets	12,322	6,051
Total current assets	179,322	202,585
Oil and natural gas properties, successful efforts method		
Unproved properties	1,838,303	1,952,680
Proved properties	2,101,875	1,602,002
Accumulated depreciation, depletion and amortization	(313,156)	(173,906)
Total oil and natural gas properties, net	3,627,022	3,380,776
Other property and equipment, net	7,388	5,465
Total property and equipment, net	3,634,410	3,386,241
Noncurrent assets		
Derivative instruments	—	662
Other noncurrent assets	25,158	27,081
Total assets	$ 3,838,890	$ 3,616,569
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 200,583	$ 199,533
Derivative instruments	—	240
Other current liabilities	529	—
Total current liabilities	201,112	199,773
Noncurrent liabilities		
Long-term debt, net	421,154	390,764
Asset retirement obligations	12,663	12,161
Deferred tax liability	42,307	9,899
Derivative instruments	2,857	—
Other long-term liabilities	596	—
Total liabilities	680,689	612,597
Shareholders' equity		
Commitments and contingencies (Note 12)		
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: 264,888,085 shares issued and 263,775,433 shares outstanding at June 30, 2018 and 261,337,636 shares issued and 260,327,920 shares outstanding at December 31, 2017	27	26
Class C (Convertible): 12,313,691 and 15,661,338 shares issued and outstanding at June 30, 2018 and December 31, 2017, respectively	1	2
Additional paid-in capital	2,819,052	2,767,558
Retained earnings	196,270	66,639
Total shareholders' equity	3,015,350	2,834,225
Noncontrolling interest	142,851	169,747
Total equity	3,158,201	3,003,972
Total liabilities and equity	$ 3,838,890	$ 3,616,569

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,	
	2018	2017	2018	2017
Operating revenues				
Oil and gas sales	$ 217,763	$ 91,064	$ 433,661	$ 152,161
Operating expenses				
Lease operating expenses	19,182	8,273	35,458	15,551
Severance and ad valorem taxes	14,208	4,723	28,381	7,910
Gathering, processing and transportation expenses	15,296	7,403	29,124	12,647
Depreciation, depletion and amortization	74,946	34,300	140,956	60,460
Impairment and abandonment expenses	1,784	—	1,784	(29)
Exploration expense	1,867	1,289	5,314	2,470
General and administrative expenses	13,809	11,822	28,106	22,706
Total operating expenses	141,092	67,810	269,123	121,715
Income from operations	76,671	23,254	164,538	30,446
Other income (expense)				
Gain (loss) on sale of oil and natural gas properties	(141)	7,191	(126)	7,357
Interest expense	(5,791)	(707)	(11,604)	(1,117)
Net gain (loss) on derivative instruments	16,697	2,529	24,540	6,288
Other income (expense)	(14)	—	(17)	—
Other income (expense)	10,751	9,013	12,793	12,528
Income before income taxes	87,422	32,267	177,331	42,974
Income tax expense	(19,940)	(9,069)	(39,077)	(9,069)
Net income	67,482	23,198	138,254	33,905
Less: Net income attributable to noncontrolling interest	3,941	2,436	8,623	3,320
Net income attributable to Class A Common Stock	$ 63,541	$ 20,762	$ 129,631	$ 30,585
Income per share of Class A Common Stock:				
Basic	$ 0.24	$ 0.09	$ 0.49	$ 0.14
Diluted	$ 0.24	$ 0.09	$ 0.49	$ 0.14

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, 2018	
	2018	2017
Cash flows from operating activities:		
Net income	$ 138,254	$ 33,905
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	140,956	60,460
Stock-based compensation expense	8,988	5,595
Abandonment expense and impairment of unproved properties	1,784	(29)
Exploratory dry hole cost	395	—
Deferred tax expense	39,077	9,069
(Gain) loss on sale of oil and natural gas properties	126	(7,357)
Non-cash portion of derivative (gain) loss	(19,016)	(6,412)
Amortization of debt issuance costs	806	214
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(16,687)	(20,567)
(Increase) decrease in prepaid and other assets	294	(172)
Increase (decrease) in accounts payable and other liabilities	28,925	18,434
Net cash provided by operating activities	323,902	93,140
Cash flows from investing activities:		
Acquisitions of oil and natural gas properties	(107,193)	(405,244)
Drilling and development capital expenditures	(469,004)	(198,299)
Purchases of other property and equipment	(3,264)	(2,457)
Proceeds from sales of oil and natural gas properties	146,090	10,675
Net cash used in investing activities	(433,371)	(595,325)
Cash flows from financing activities:		
Issuance of Class A common shares	—	340,750
Underwriters discount and offering costs	—	(7,233)
Proceeds from revolving credit facility	115,000	50,000
Repayment of revolving credit facility	(85,000)	(15,000)
Proceeds from stock options exercised	575	—
Restricted stock used for tax withholdings	(257)	—
Debt issuance costs	(4,044)	(415)
Net cash provided by financing activities	26,274	368,102
Net decrease in cash and cash equivalents and restricted cash	(83,195)	(134,083)
Cash and cash equivalents and restricted cash, beginning of period	125,915	134,083
Cash and cash equivalents, end of period	$ 42,720	$ —

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

Supplemental cash flow information and noncash activity (in thousands):

	For the Six Months Ended June 30,	
	2018	2017
Supplemental cash flow information		
Cash paid for interest	$ 1,157	$ 723
Supplemental non-cash activity		
Accrued capital expenditures included in accounts payable and accrued expenses	$ 97,711	$ 80,651
Asset retirement obligations incurred, including revisions to estimates	659	649

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

	Common Stock				Preferred Stock								
	Class A		Class C		Series A		Series B						
	Shares	Amount	Shares	Amount	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total Shareholder's Equity	Non-controlling Interest	Total Equity
Balance at December 31, 2016	201,092	$ 20	19,156	$ 2	—	$ —	104	$ —	$ 2,364,049	$ (8,929)	$ 2,355,142	$ 197,793	$ 2,552,935
Warrants exercised	6,236	1	—	—	—	—	—	—	(1)	—	—	—	—
Restricted stock issued	324	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(7)	—	—	—	—	—	—	—	—	—	—	—	—
Conversion of Series B preferred shares to Class A common shares	26,100	3	—	—	—	—	(104)	—	(3)	—	—	—	—
Sale of unregistered Class A common shares	23,500	2	—	—	—	—	—	—	340,748	—	340,750	—	340,750
Underwriters' discount and offering expense	—	—	—	—	—	—	—	—	(7,233)	—	(7,233)	—	(7,233)
Stock-based compensation	—	—	—	—	—	—	—	—	5,595	—	5,595	—	5,595
Change in equity due to issuance of shares by Centennial Resource Production, LLC	—	—	—	—	—	—	—	—	(2,682)	—	(2,682)	2,682	—
Net income	—	—	—	—	—	—	—	—	—	30,585	30,585	3,320	33,905
Balance at June 30, 2017	257,245	$ 26	19,156	$ 2	—	$ —	—	$ —	$ 2,700,473	$ 21,656	$ 2,722,157	$ 203,795	$ 2,925,952
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	222	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock forfeited	(43)	—	—	—	—	—	—	—	—	—	—	—	—
Restricted stock used for tax withholding	(14)	—	—	—	—	—	—	—	(257)	—	(257)	—	(257)
Option Exercises	38	—	—	—	—	—	—	—	575	—	575	—	575
Stock-based compensation	—	—	—	—	—	—	—	—	8,988	—	8,988	—	8,988
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	—	—	—	—	—	—	—	—	—	129,631	129,631	8,623	138,254
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. The Company's assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin, and its properties consist primarily 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 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, 2017 (the "2017 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 2017 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. Certain prior period amounts have been reclassified to conform to the current presentation in the accompanying consolidated financial statements. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Noncontrolling interest represents third-party ownership in the Company's consolidated subsidiary, and it is presented as a component of equity. See *Note 9—Shareholders' Equity and Noncontrolling Interest* for further discussion of noncontrolling interest.

Use of Estimates

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

The more significant areas requiring the use of assumptions, judgments and estimates include: (i) oil and natural gas reserves; (ii) cash flow estimates used in impairment tests of long-lived assets; (iii) 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 derivative instruments; 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 jurisdictions, permanent and temporary differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

Recently Issued Accounting Standards

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*. This update applies to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years with early adoption permitted. This update should be applied using the retrospective transition method. The Company adopted ASU 2016-15 in the first quarter of 2018. As a result of adoption, there were no changes to the presentation of cash flow activities in the statement of cash flows for the six months ended June 30, 2018.

In February 2016, the FASB issued ASU 2016-02, *Leases*, which created Accounting Standard Codification ("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 the statement of financial position 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 the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. ASC Topic 842 will be 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 will adopt this guidance as of January 1, 2019, the effective date, and plans to recognize a cumulative-effect adjustment at the time of adoption. Although the Company is still in the process of evaluating the effect of adopting ASC Topic 842 and its related amendments, the adoption is expected to result in the recognition of assets and liabilities on its Consolidated Balance Sheet for current operating leases such as drilling rig contracts and office rental agreements. The Company is continuing to evaluate existing arrangements to determine if they qualify for lease accounting under ASC Topic 842.

In May 2014, the FASB issued ASU 2014-09, which created ASC Topic 606, *Revenue from Contracts with Customers* ("ASC Topic 606"), superseding revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, and most industry-specific guidance. The FASB subsequently issued various ASUs which deferred the effective date of ASC Topic 606 and provided additional implementation guidance. ASC Topic 606 provides companies with a single model for use in accounting for revenue arising from contracts with customers. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. In addition, new qualitative and quantitative disclosure requirements aim to enable financial statement users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. ASC Topic 606 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented or (ii) recognition of a cumulative-effect adjustment as of the date of initial application. The Company has selected the modified retrospective method and has adopted this guidance as of January 1, 2018, the effective date. The Company has completed its review of the impact of the new standard on its significant contracts and concluded that there was not a material impact to the presentation of revenues or expenses as a result of the adoption of this standard. Refer to *Note 13—Revenues* for additional disclosures required by the new standard.

Note 2—Property Acquisitions and Divestiture

Acquisition

On February 8, 2018, the Company completed the acquisition of approximately 4,000 undeveloped net acres, as well as certain producing properties, in Lea County, New Mexico for an unadjusted purchase price of $94.7 million. The operated acreage position contains an approximate 92% average working interest and is largely contiguous to Centennial's existing positions in the northern Delaware Basin. Upon signing the purchase and sale agreement, the Company placed $8.6 million of cash in escrow accounts on December 21, 2017, and such deposits were applied as a payment against the purchase price upon closing of the transactions. The Company presented the cash in escrow as restricted cash within the line item *Other Noncurrent Assets* in the Consolidated Balance Sheet as of December 31, 2017.

The acquisition was recorded as an asset acquisition under ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*. Accordingly, the purchase consideration has been allocated to the oil and natural gas properties based on their relative fair values measured as of the acquisition date. After settlement statement adjustments of $0.2 million, the Company paid a net purchase price of $94.5 million. On a relative fair value basis, $80.7 million was allocated to unproved properties and $13.8 million to proved properties. Transaction costs incurred and capitalized as of June 30, 2018, amounted to $0.2 million and mainly consisted of advisory and legal fees.

Disposition

On March 2, 2018, the Company completed the sale of approximately 8,600 undeveloped net acres and 12 gross producing wells located in Reeves County, Texas for a total unadjusted sales price of $140.7 million. The divested acreage represents a largely non-operated position (32% average working interest) on the western portion of Centennial's position in Reeves County. There was no gain or loss recognized as a result of this divestiture, which constituted a partial sale of oil and gas properties in accordance with ASC 932*, Extractive Activities - Oil and Gas*. The Company used the net proceeds from the sale to fund the 2018 acquisition discussed above and for general corporate purposes.

Note 3—Accounts Receivable, Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

(in thousands)	June 30, 2018	December 31, 2017
Accrued oil and gas sales receivable, net	$ 63,222	$ 52,891
Joint interest billings	37,700	25,256
Receivables for divestitures	416	—
Other	215	639
Accounts receivable, net	$ 101,553	$ 78,786

Accounts payable and accrued expenses are comprised of the following:

(in thousands)	June 30, 2018	December 31, 2017
Accounts payable	$ 36,586	$ 64,004
Accrued capital expenditures	92,278	90,511
Revenues payable	40,662	23,390
Accrued interest	13,001	1,936
Accrued employee compensation and benefits	4,791	8,350
Accrued expenses and other	13,265	11,342
Accounts payable and accrued expenses	$ 200,583	$ 199,533

Note 4—Long-Term Debt

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, 2018, had a borrowing base of $800.0 million and elected commitments of $600.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. As of June 30, 2018, the Company had $30.0 million borrowings outstanding and $569.1 million in available borrowing capacity, which was net of $0.9 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 each April 1 and October 1 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.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the credit agreement and are discussed in "*Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources"* later in this Quarterly Report. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount and are included in interest expense in the Consolidated Statements of Operations. The credit facility provides for interest only payments until May 4, 2023, when the credit agreement expires and all outstanding borrowings are due.

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, 2018 and through the filing of this Quarterly Report.

5.375% Senior Unsecured Notes due 2026

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (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 Senior Notes semi-annually in arrears on each January 15 and July 15, commencing 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 indenture governing the Senior Notes.

At any time prior to January 15, 2021, CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the 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% of the principal amount of the Senior Notes redeemed, plus any accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount issued under the indenture governing the Senior Notes remains outstanding immediately after such redemption, and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to January 15, 2021, 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 January 15, 2021, CRP may redeem the Senior Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.688% for the 12-month period beginning on January 15, 2021, 101.344% for the 12-month period beginning January 15, 2022, and 100% beginning on January 15, 2023, 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 indenture 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, 2018 and through the filing of this Quarterly Report.

Upon an Event of Default (as defined in the indenture 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.

Debt issuance costs netted against the principal balance of the Senior Notes amounted to $8.8 million as of June 30, 2018 and $9.2 million as of December 31, 2017.

Note 5—Asset Retirement Obligations

The following table summarizes the changes in the Company's asset retirement obligations ("ARO") for the six months ended June 30, 2018 (in thousands):

Asset retirement obligations at January 1, 2018	$	12,161
Liabilities acquired		16
Liabilities incurred		670
Liabilities divested and settled		(556)
Accretion expense		383
Revisions to estimated cash flows		(11)
Asset retirement obligations at June 30, 2018	$	12,663

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 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.

Note 6—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, 2018, the Company had 10,559,339 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. Upon adoption of ASU 2016-09 in October 2016, the Company elected to account for forfeitures of awards granted under the LTIP as they occur in determining compensation expense.

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

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)	**2018**	**2017**	**2018**	**2017**
Restricted stock awards	$ 1,989	$ 1,018	$ 3,764	$ 1,874
Stock option awards	2,310	1,967	4,516	3,721
Performance stock units	356	—	708	—
Total stock-based compensation expense	$ 4,655	$ 2,985	$ 8,988	$ 5,595

Restricted Stock

The following table provides information about restricted stock awards outstanding during the six months ended June 30, 2018:

	Awards	Weighted Average Grant Date Fair Value
Unvested balance as of December 31, 2017	1,009,716	$ 17.64
Granted	221,505	18.87
Vested	(75,272)	18.36
Forfeited	(43,298)	17.01
Unvested balance as of June 30, 2018	1,112,651	17.86

The Company grants service-based restricted stock awards to executive officers and employees, which generally vest ratably over a three-year service period, and to directors, which generally vest over a one-year service period. Compensation cost for the service-based restricted stock awards is based upon the grant-date fair value of the award, and such costs are recognized ratably over the applicable vesting period. The weighted average grant-date fair value for restricted stock awards granted was $18.87 per share and $18.77 per share for the six months ended June 30, 2018 and 2017, respectively. The total fair value of restricted stock awards that vested during the six months ended June 30, 2018 was $1.4 million, and no awards vested during the six months ended June 30, 2017. Unrecognized compensation cost related to restricted shares that were unvested as of June 30, 2018 was $14.7 million, which the Company expects to recognize over a weighted average period of 2.0 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 related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. 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, 2018:

	For the Six Months Ended June 30,	
	2018	**2017**
Weighted average grant-date fair value per share	$ 7.82	$ 7.15
Expected term (in years)	6	6
Expected stock volatility	41.1%	38.1%
Dividend yield	—%	—%
Risk-free interest rate	2.5%	2.0%

The following table provides information about stock option awards outstanding during the six months ended June 30, 2018:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding as of December 31, 2017	4,290,001	$ 16.15		
Granted	226,500	18.10		
Exercised	(38,332)	15.05		
Forfeited	(106,002)	15.86		
Outstanding as of June 30, 2018	4,372,167	16.27	8.6	$ 8,200
Exercisable as of June 30, 2018	1,122,775	15.81	8.4	2,522
Unvested Options at June 30, 2018	3,160,171	16.36	8.6	5,677

As of June 30, 2018, there was $15.3 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 1.57 years.

Performance Stock Units

During the six months ended June 30, 2018, there was no performance stock units activity. As of June 30, 2018, there was $2.9 million of unrecognized compensation cost related to performance stock units that were unvested, which the Company expects to recognize on a pro-rata basis over a weighted average period of 2.0 years.

Note 7—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 periodically uses derivative instruments, such as swaps, 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 opportunistically uses 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, 2018:

	Period	Volume (Bbl)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl) [(1)]
Crude oil basis swaps	July 2018 - September 2018	828,000	9,000	$ (2.38)
	October 2018 - December 2018	828,000	9,000	(2.38)
	January 2019 - March 2019	540,000	6,000	(5.34)
	April 2019 - June 2019	91,000	1,000	(10.00)
	July 2019 - September 2019	1,380,000	15,000	(9.03)
	October 2019 - December 2019	552,000	6,000	(4.23)

(1) The crude oil basis swap contracts are settled based on the difference between the arithmetic average of ARGUS MIDLAND WTI and ARGUS WTI CUSHING settlements during the relevant calculation period.

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

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu) (1)
Natural Gas Swaps - Henry Hub	January 2019 - December 2019	10,950,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	January 2019 - December 2019	5,475,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu) (2)
Natural gas basis swaps	July 2018 - December 2018	920,000	5,000	$ (0.43)
	January 2019 - December 2019	12,775,000	35,000	(1.31)

(1) The natural gas swap contracts are settled based on the month's average daily NYMEX price of Henry Hub Natural Gas or Inside FERC's West Texas WAHA price of natural gas.

(2) The natural gas basis swap contracts are settled based on the difference between Inside FERC's West Texas WAHA price of natural gas and the NYMEX price of Henry Hub Natural Gas during the relevant calculation period.

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

The following table presents gains and losses for derivative instruments not designated as hedges for accounting purposes for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Net gain (loss) on derivative instruments	$ 16,697	$ 2,529	$ 24,540	$ 6,288

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 sheet dates. Refer to *Note 8—Fair Value Measurements* for details of the gross and net derivative assets, liabilities and offset amounts as presented in the Consolidated Balance Sheets.

		Gross Asset/Liability Amounts	
(in thousands)	**Balance Sheet Classification**	**June 30, 2018**	**December 31, 2017**
Derivative Assets			
Derivative instruments	Current assets	$ 23,991	$ 720
Derivative instruments	Noncurrent assets	1,622	662
Total derivative assets		$ 25,613	$ 1,382
Derivative Liabilities			
Derivative instruments	Current liabilities	$ 1,264	$ 527
Derivative instruments	Noncurrent liabilities	4,479	—
Total derivative liabilities		$ 5,743	$ 527

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 the Company 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 lender under CRP's credit facility as referenced above.

Note 8—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 the Company's netted asset or liability positions that have been measured at fair value and where they have been classified within the fair value hierarchy as of June 30, 2018 and December 31, 2017:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities			Netting Adjustments[1]	Net Amounts Presented on the Balance Sheets
	Level 1	Level 2	Level 3		
(in thousands)	June 30, 2018				
Financial assets					
Commodity derivative asset - current	$ —	$ 23,991	$ —	$ (1,264)	$ 22,727
Commodity derivative asset - noncurrent	—	1,622	—	(1,622)	—
Total financial assets	$ —	$ 25,613	$ —	$ (2,886)	$ 22,727
Financial liabilities					
Commodity derivative liability - current	$ —	$ 1,264	$ —	$ (1,264)	$ —
Commodity derivative liability - noncurrent	—	4,479	—	(1,622)	2,857
Total financial liabilities	$ —	$ 5,743	$ —	$ (2,886)	$ 2,857
	December 31, 2017				
Financial Assets					
Commodity derivative asset - current	$ —	$ 720	$ —	$ (287)	$ 433
Commodity derivative asset - noncurrent	—	662	—	—	662
Total financial assets	$ —	$ 1,382	$ —	$ (287)	$ 1,095
Financial liabilities					
Commodity derivative liability - current	$ —	$ 527	$ —	$ (287)	$ 240

(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.

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.

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. Refer to *Note 2—Property Acquisitions and Divestiture* for additional information on the fair value of assets acquired during 2018 and 2017.

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 5—Asset Retirement Obligations* for additional information on the Company’s ARO.

Other Financial Instruments

The carrying amounts of the Company’s cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate their fair values because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying values of the amounts outstanding under CRP’s credit agreement, if any, 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. As of June 30, 2018 and December 31, 2017, the fair value of the Senior Notes was $389.0 million and $407.5 million, respectively, which were determined using quoted market prices for this same debt security, a Level 1 classification in the fair value hierarchy.

Note 9—Shareholders' Equity and Noncontrolling Interest

Shareholders’ Equity

On March 7, 2018, Silver Run Sponsor, LLC (“Silver Run Sponsor”), the Riverstone Purchasers and the Centennial Contributors completed an underwritten public offering of 25,000,000 shares of Class A Common Stock. No cash proceeds were received by the Company in connection with this offering and 3,347,647 shares of CRP Common Units (and corresponding shares of Class C Common Stock) were converted to shares of Class A Common Stock on a one-to-one basis. A tax benefit of $6.7 million was recorded in equity as a result of the conversion of shares from the noncontrolling interest owner.

Noncontrolling Interest

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

As of June 30, 2018, the noncontrolling interest ownership of CRP decreased to 4.5% from 5.7% as of December 31, 2017. The decrease was the result of the exchange of CRP Common Units (and corresponding shares of Class C Common Stock) for Class A Common Stock in March 2018 as discussed in the preceding section above.

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

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

Note 10—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.

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings.

Shares of the Company's unvested restricted stock and performance stock units are eligible to receive dividends; however, dividend rights will be forfeited if the award does not vest. Accordingly, these shares are not considered participating securities. Shares of the Company's Class C Common Stock and warrants do not share in earnings or losses and are therefore not participating securities. The Company's shares of Series B Preferred Stock had a non-forfeitable right to participate in distributions with common stockholders on a pro-rata, as-converted basis. All of Company's shares of Series B Preferred Stock were converted into shares of Class A Common Stock on May 25, 2017 in accordance with their terms. As such, the Company no longer has any participating securities as of June 30, 2018 and 2017.

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)	**2018**	**2017**	**2018**	**2017**
Net income attributable to Class A Common Stock	$ 63,541	$ 20,762	$ 129,631	$ 30,585
Add: Income from conversion of Class C Common Stock	—	1,477	—	1,995
Adjusted net income attributable to Class A Common Stock	63,541	22,239	129,631	32,580
Basic net earnings per share of Class A Common Stock	$ 0.24	$ 0.09	$ 0.49	$ 0.14
Diluted net earnings per share of Class A Common Stock	$ 0.24	$ 0.09	$ 0.49	$ 0.14
Basic weighted average shares of Class A Common Stock outstanding	263,757	223,623	262,547	212,759
Add: Dilutive effects of equity awards	3,249	925	3,554	2,046
Add: Dilutive effects of conversion	—	19,156	—	19,156
Diluted weighted average shares of Class A Common Stock outstanding	267,006	243,704	266,101	233,961

For the three and six months ended June 30, 2018 and 2017, 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)	**2018**	**2017**	**2018**	**2017**
Out-of-the-money stock options	643	1,498	407	818
Weighted average shares of Class C Common Stock	12,314	—	13,497	—
Performance stock units	155	—	77	—

Note 11—Transactions with Related Parties

The Company obtains services related to its drilling and completion activities from related parties from time to time. The Company believes that the terms of the arrangements with these related parties are no less favorable to either party than those held with unaffiliated parties. The following table summarizes the costs incurred for such services which were either included as part of oil and natural gas properties in the Consolidated Balance Sheet or as lease operating expense in the Consolidated Statements of Operations, as well as the related payables outstanding as of the balance sheet dates:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
Costs of goods/services provided				
Liberty Oilfield Services, LLC[(1)]	$ —	$ 27,675	$ —	$ 40,182
Permian Tank and Manufacturing, Inc.[(1)]	1,780	1,308	3,767	2,365
Oil States International, Inc.[(2)]	2,106	3,236	4,401	3,932

(in thousands)	**June 30, 2018**	**December 31, 2017**
Accounts payable and accrued expenses		
Permian Tank and Manufacturing, Inc.[(1)]	$ 1,816	$ 340
Oil States International, Inc.[(2)]	598	1,518

(1) These entities are Riverstone affiliates. Riverstone and its affiliates, beneficially own more than 10% equity interest in the Company and are therefore considered related parties.

(2) Mark G. Papa, the Company's President, Chief Executive Officer and Chairman of the Board, serves as a director and Chairman of the Board of Oil States International, Inc., an energy services company publicly traded on the New York Stock Exchange ("Oil States").

Note 12—Commitments and Contingencies

Commitments

In 2018, the Company entered into various natural gas transportation agreements whereby it is required to deliver approximately 491,000,000 MMBtu, in aggregate, over a term ranging from one to four years or else pay for any volume deficiencies. These delivery commitments are tied to the Company's natural gas production, and the aggregate financial obligation under these contracts is $38.7 million, representing the minimum commitments pursuant to the terms of these agreements as of June 30, 2018. Actual expenditures under these contracts may exceed this minimum commitment amount. The following table summarizes the natural gas volumes the Company is required to deliver by period under these agreements as well as its existing natural gas transportation agreements:

Period	Total Volume Commitments (MMBtu)	Volume (MMBtu/d)
July 2018 - December 2018	22,300,000	121,500
January 2019 - December 2019	116,800,000	320,000
January 2020 - December 2020	194,800,000	533,600
January 2021 - December 2021	158,100,000	433,200
January 2022 - October 2022	19,700,000	64,800
Total	511,700,000	

In May 2018, the Company entered into a three-year supply agreement to purchase frac sand from an in-basin sand mine in West Texas. Under the terms of the agreement, the Company is obligated to purchase a minimum volume of sand at a fixed sales price. The aggregate financial obligation under this contract is $25.2 million, which represents the minimum commitments pursuant to the terms of the agreement as of June 30, 2018. Actual expenditures under this contract may exceed this minimum commitment amount.

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. Other than those discussed above, there have been no material, non-routine changes in commitments during the six months ended June 30, 2018. Please refer to *Note 13—Commitments and Contingencies* included in Part II, Item 8 in the Company's 2017 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 13—Revenues

Revenue from Contracts with Customers

Sales of crude oil and natural gas are recognized at the point 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 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.

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

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,	
	2018	2017	2018	2017
Operating revenues (in thousands):				
Oil sales	$ 174,156	$ 70,735	$ 348,997	$ 117,416
Natural gas sales	13,721	12,133	32,301	20,374
NGL sales	29,886	8,196	52,363	14,371
Oil and gas sales	$ 217,763	$ 91,064	$ 433,661	$ 152,161

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 custody, title and risk of loss 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 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 Sheet. As of June 30, 2018 and December 31, 2017, such receivable balances were $63.2 million and $52.9 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 the six months ended June 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was 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 14—Subsequent Events

On August 2, 2018, the Company entered into a firm sales agreement with a large diversified crude oil purchaser. Utilizing the purchaser's existing firm transport capacity out of the Permian Basin, the six-year agreement provides for firm gross sales of 20,000 Bbls/d beginning in January 2019, increasing to 30,000 Bbls/d upon the earlier of (i) the in-service date of the pipeline system that is currently being constructed by Gray Oak Pipeline, LLC, or (ii) June 1, 2020, through the remainder of the agreement. This sales agreement requires the Company to physically deliver the aforementioned volumes of crude oil over the contractual term. The Company believes its current production and reserves are sufficient to fulfill this delivery commitment, but if the physical delivery commitment is not met, a financial obligation may arise. However, the aggregate amount of any such potential financial obligation under this contract is not determinable since the amount and timing of any volumetric shortfalls, as well as the difference between the prevailing market price and contract price at such time, cannot be predicted with accuracy.

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 2017 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 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 repeatable success and return on capital.

Market Conditions

The oil and natural gas industry is cyclical, and commodity prices can be volatile. During 2016, global and domestic oil supply continued to outpace demand resulting in ongoing low realized oil and gas prices. In 2017 and thus far into 2018, commodity prices have improved yet remain volatile, and it is likely that commodity prices will continue to fluctuate due to global supply and demand, inventory supply levels, weather conditions, geopolitical, and other factors.

The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2016:

	2016				2017				2018	
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Crude oil (per Bbl)	$ 33.49	$ 45.70	$ 45.00	$ 49.27	$ 51.82	$ 48.32	$ 48.17	$ 55.31	$ 62.91	$ 68.07
Natural gas (per MMBtu)	$ 1.98	$ 2.25	$ 2.80	$ 3.17	$ 3.06	$ 3.14	$ 2.95	$ 2.91	$ 3.08	$ 2.85

Although oil and natural gas prices have begun to recover from the lows experienced during the first quarter of 2016, forecast prices for both oil and natural gas have not rebounded to pre-2015 levels. 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 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.

2018 Highlights and Future Considerations

Operational Highlights

We operated, on average, a seven-rig drilling program during the first half of 2018 which allowed us to complete 20 gross operated productive wells in the second quarter and 36 gross operated wells year to date. The total number of completed wells during the year had an average effective lateral length of approximately 7,300 feet.

Acquisition and Divestiture Highlights

On February 8, 2018, we completed the acquisition of approximately 4,000 undeveloped net acres, as well as certain producing properties, in the core of the Northern Delaware Basin in Lea County, New Mexico for an unadjusted purchase price of $94.7 million. The operated acreage position contains 92% average working interest and is largely contiguous to Centennial's existing position.

On March 2, 2018, we completed the sale of approximately 8,600 undeveloped net acres and 12 gross producing wells located in Reeves County, Texas for a total unadjusted sales price of $140.7 million. The divested acreage represents a largely non-operated position (32% average working interest) on the western portion of Centennial's acreage in Reeves County. The properties divested consisted of 1,987 MBoe of proved reserves as of December 31, 2017, representing approximately 1% of our proved reserves as of that date, and generated 769 Boe/d (608 Bbls/d) in the first quarter of 2018.

Financing Highlights

On May 4, 2018, the Company entered into an amended and restated credit agreement (the "Amended Agreement") with a syndicate of banks, the majority of which were lenders to the Company's existing credit agreement. Under the Amended Agreement, the borrowing base increased from $575.0 million to $800.0 million and aggregate elected commitments increased from $475.0 million to $600.0 million. The Amended Agreement also provided for lower rates and fees compared to the existing credit agreement, with varying rates depending on the percentage of the borrowing base utilized, as follows: the LIBOR margin decreased from the range of 225 to 325 basis points to 150 to 250 basis points; the alternate base rate margin decreased from the range of 125 to 225 basis points to 50 to 150 basis points; and the commitment fees, which are paid on unused amounts of the revolving credit facility, were reduced from 50 basis points to a range of 37.5 to 50 basis points. The credit facility under the Amended Agreement has a term of five years.

Results of Operations

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

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)	
	2018	2017	$	%
Operating revenues (in thousands):				
Oil sales	$ 174,156	$ 70,735	$ 103,421	146 %
Natural gas sales	13,721	12,133	1,588	13 %
NGL sales	29,886	8,196	21,690	265 %
Oil and gas sales	$ 217,763	$ 91,064	$ 126,699	139 %
Average sales prices:				
Oil (per Bbl)	$ 61.21	$ 44.57	$ 16.64	37 %
Effect of derivative settlements on average price (per Bbl)	1.69	0.24	1.45	604 %
Oil net of hedging (per Bbl)	$ 62.90	$ 44.81	$ 18.09	40 %
Average NYMEX price for oil (per Bbl)	$ 68.07	$ 48.32	$ 19.75	41 %
Oil differential to NYMEX	(6.86)	(3.75)	(3.11)	83 %
Natural gas (per Mcf)	$ 1.81	$ 2.78	$ (0.97)	(35)%
Effect of derivative settlements on average price (per Mcf)	0.05	(0.02)	0.07	350 %
Natural gas net of hedging (per Mcf)	$ 1.86	$ 2.76	$ (0.90)	(33)%
Average NYMEX price for natural gas (per Mcf)	$ 2.85	$ 3.14	$ (0.29)	(9)%
Natural gas differential to NYMEX	(1.04)	(0.36)	(0.68)	189 %
NGL (per Bbl)	$ 26.52	$ 21.34	$ 5.18	24 %
Net production:				
Oil (MBbls)	2,845	1,587	1,258	79 %
Natural gas (MMcf)	7,572	4,372	3,200	73 %
NGL (MBbls)	1,127	384	743	193 %
Total (MBoe)	5,235	2,700	2,535	94 %
Average daily net production volume:				
Oil (Bbls/d)	31,271	17,435	13,836	79 %
Natural gas (Mcf/d)	83,205	48,042	35,163	73 %
NGL (Bbls/d)	12,389	4,222	8,167	193 %
Total (Boe/d)	57,528	29,664	27,864	94 %

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the three months ended June 30, 2018 were $126.7 million (or 139%) higher than total net revenues for the three months ended June 30, 2017. 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 79%, 73% and 193%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin, as well as the producing properties acquired in the GMT Acquisition, which added 64 MBbls of net oil production to our second quarter 2018 results. Since the second quarter 2017, 75 gross operated wells were placed on production in the Delaware Basin, which added 1,879 MBbls of net oil production. The increase in the Company's operated well count is attributable to the continued ramp up of development drilling activities and a seven-rig drilling program in the first half of 2018. 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. During the second quarter of 2018, however, our production was made up of 46% natural gas and NGL volumes compared to 41% in the second quarter of 2017. This change in our commodity mix was due to the significant increase in NGL volumes (up 193%) between periods, which was primarily a result of the main processor of our wet gas switching from ethane-rejection to ethane-recovery. This switch enabled us to recover an increased amount of ethane from our wet gas. The change to recover a higher portion of ethane started in the second quarter of 2018 and was made due to lower natural gas prices in the Permian Basin and higher ethane prices, which in turn led to stronger ethane processing economics.

In addition to production-related increases in net revenue between periods, there were also significant increases in our average realized sales prices for oil and NGLs in the second quarter of 2018 compared to the same 2017 period. The average price for oil before the effects of hedging increased 37%, and the average price for NGLs increased 24% between periods. The 37% increase in average realized oil price was a result of higher NYMEX crude prices between periods (average NYMEX prices increased 41%), which were partially offset by lower realizations due to wider oil differentials in the second quarter of 2018. The 24% increase in average realized NGL prices between periods was primarily attributable to higher Mont Belvieu spot prices for plant products in the second quarter 2018 as compared to the second quarter of 2017. Conversely, the average realized sales price of natural gas decreased by 35% from second quarter 2017 to second quarter 2018. This decrease was mainly due to significantly wider gas differentials and lower NYMEX prices between periods (average NYMEX gas prices being 9% lower between periods). Both our oil and gas differentials widened during the second quarter 2018 due to anticipated pipeline takeaway capacity constraints expected to impact Permian Basin market differentials.

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

	For the Three Months Ended June 30,		Increase/(Decrease)	
	2018	**2017**	**$**	**%**
Operating costs (in thousands):				
Lease operating expenses	$ 19,182	$ 8,273	$ 10,909	132%
Severance and ad valorem taxes	14,208	4,723	9,485	201%
Gathering, processing and transportation expenses	15,296	7,403	7,893	107%
Operating costs per Boe:				
Lease operating expenses	$ 3.66	$ 3.06	$ 0.60	20%
Severance and ad valorem taxes	2.71	1.75	0.96	55%
Gathering, processing and transportation expenses	2.92	2.74	0.18	7%

Lease Operating Expenses. Lease operating expenses (“LOE”) for the three months ended June 30, 2018 increased $10.9 million compared to the three months ended June 30, 2017. Higher LOE for the second quarter of 2018 was primarily related to a $10.5 million increase in expense associated with a higher well count. We had 217 gross operated horizontal wells as of June 30, 2018 as compared to 158 gross operated horizontal wells as of June 30, 2017. The increase in well count was mainly the result of successful drilling activity which added 75 gross operated wells since the second quarter of 2017, which was partially offset by divestiture activity. Workover activity remained relatively consistent between periods at $2.6 million and $2.2 million for the second quarter of 2018 and 2017, respectively.

LOE on a per Boe basis increased when comparing the second quarter of 2018 to the same 2017 period. LOE per Boe was $3.66 for the second quarter of 2018, which represents an increase of $0.60 per Boe from the second quarter of 2017. This increase in rate was mainly due to higher costs associated with water handling and equipment rentals for our existing and newly completed wells.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of production at the wellhead, and 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 taxes for the three months ended June 30, 2018 increased $6.6 million compared to the three months ended June 30, 2017 primarily due to higher oil, natural gas and NGL revenues between periods. Severance and ad valorem taxes as a percentage of total net revenues increased to 7% for the three months ended June 30, 2018 as compared to 5% in 2017 due to increased ad valorem taxes of $2.9 million between periods, associated with higher well count and higher oil and gas property values.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses (“GP&T”) for the three months ended June 30, 2018 increased $7.9 million compared to the three months ended June 30, 2017 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing fees and transportation and gathering costs being incurred between periods.

On a per Boe basis, GP&T increased 7% from $2.74 for the second quarter of 2017 to $2.92 per Boe for the second quarter of 2018. This increase in rate was primarily due to a change in our commodity mix whereby a higher percentage of our total production was made up of natural gas and NGL volumes during the second quarter of 2018, and thus a higher proportion of our production during this 2018 period was subject to gas gathering and transportation charges as well as gas processing fees. Conversely, on a natural gas and NGL volumes basis (i.e. excluding crude oil barrels) the Boe rate decreased 4% between periods from $6.65 to $6.40 for the second quarters of 2017 and 2018, respectively. This decrease was attributable to lower natural gas prices between periods, which are a cost component of gas processing fees.

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)	**2018**	**2017**
Depreciation, depletion and amortization	$ 74,946	$ 34,300
Depreciation, depletion and amortization per Boe	14.32	12.70

DD&A rate can fluctuate as a result of finding and development costs, acquisitions, impairments, as well as changes in proved reserves or proved developed reserves. For the three months ended June 30, 2018, DD&A expense amounted to $74.9 million, an increase of $40.6 million over the same 2017 period. This higher DD&A in 2018 was related to increases in overall production volumes as well as higher DD&A rates between periods, which resulted in $32.1 million and $8.5 million, respectively, of incremental DD&A expense being incurred during the second quarter of 2018.

DD&A per Boe was $14.32 for the second quarter of 2018 compared to $12.70 for the same period in 2017. The primary factor contributing to this higher DD&A rate was increased drilling and completion costs incurred for new wells completed and placed on production over the past 12 months.

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

	For the Three Months Ended June 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 489	$ 427
Exploratory dry hole costs	174	—
Geological and geophysical costs	1,204	862
Exploration expense	$ 1,867	$ 1,289

Exploration expense was $1.9 million for the three months ended June 30, 2018 compared to $1.3 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 related to increased salaries and related expenses of G&G personnel as a result of four geologists added to our staff since the second quarter of 2017.

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)	**2018**	**2017**
Stock-based compensation expense	$ 4,166	$ 2,558
Cash general and administrative expenses	9,643	9,264
General and administrative expenses	$ 13,809	$ 11,822

G&A expenses for the three months ended June 30, 2018 were $13.8 million compared to $11.8 million for the three months ended June 30, 2017. The higher G&A expenses incurred in 2018 were primarily due to $1.9 million in increased employee salaries and payroll burdens and $1.6 million in higher stock-based compensation compared to the prior year period. G&A personnel costs were higher during the second quarter of 2018 due to the number of administrative employees increasing from 80 as of June 30, 2017 to 104 as of June 30, 2018. These increases were partially offset by lower professional fees and transaction costs incurred during the second quarter of 2018 as compared to second quarter of 2017.

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)	**2018**	**2017**
Credit facility	$ 687	$ 586
Senior Notes	5,375	—
Amortization of debt issuance costs	427	121
Interest capitalized	(698)	—
Total	$ 5,791	$ 707

Interest expense was $5.1 million higher for the three months ended June 30, 2018 compared to the three months ended June 30, 2017 primarily due to the issuance of Senior Notes in November 2017, which was partially offset by capitalized interest.

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 Three Months Ended June 30,	
(in thousands)	**2018**	**2017**
Cash derivative settlement gain	$ 5,163	$ 273
Non-cash mark-to-market derivative gain	11,534	2,256
Net gain (loss) on derivative instruments	$ 16,697	$ 2,529

Income Tax Expense. During the three months ended June 30, 2018 and 2017, the Company recognized income tax expense amounting to $19.9 million and $9.1 million, respectively. The increase in income tax expense for the three months ended June 30, 2018 as compared to the same period in 2017 was primarily due to an increase in taxable income during the second quarter of 2018, partially offset by a lower effective federal tax rate. The enactment of the Jobs Act in December 2017 reduced the corporate tax rate to 21%.

The Company's provision for income taxes for the second quarter of 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax income because of state income taxes and permanent differences.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	For the Six Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating revenues (in thousands):				
Oil sales	$ 348,997	$ 117,416	$ 231,581	197 %
Natural gas sales	32,301	20,374	11,927	59 %
NGL sales	52,363	14,371	37,992	264 %
Oil and gas sales	$ 433,661	$ 152,161	$ 281,500	185 %
Average sales prices:				
Oil (per Bbl)	$ 61.37	$ 46.39	$ 14.98	32 %
Effect of derivative settlements on average price (per Bbl)	0.89	0.05	0.84	1,680 %
Oil net of hedging (per Bbl)	$ 62.26	$ 46.44	$ 15.82	34 %
Average NYMEX price for oil (per Bbl)	$ 65.55	$ 50.05	$ 15.50	31 %
Oil differential to NYMEX	(4.18)	(3.66)	(0.52)	14 %
Natural gas (per Mcf)	$ 2.12	$ 2.83	$ (0.71)	(25)%
Effect of derivative settlements on average price (per Mcf)	0.03	(0.04)	0.07	175 %
Natural gas net of hedging (per Mcf)	$ 2.15	$ 2.79	$ (0.64)	(23)%
Average NYMEX price for natural gas (per Mcf)	$ 2.96	$ 3.10	$ (0.14)	(5)%
Natural gas differential to NYMEX	(0.84)	(0.27)	(0.57)	211 %
NGL (per Bbl)	$ 27.99	$ 22.81	$ 5.18	23 %
Net production:				
Oil (MBbls)	5,687	2,531	3,156	125 %
Natural gas (MMcf)	15,255	7,205	8,050	112 %
NGLs (MBbls)	1,871	630	1,241	197 %
Total (MBoe)	10,101	4,362	5,739	132 %
Average daily net production volume:				
Oil (Bbls/d)	31,421	13,982	17,439	125 %
Natural gas (Mcf/d)	84,283	39,807	44,476	112 %
NGLs (Bbls/d)	10,340	3,481	6,859	197 %
Total (Boe/d)	55,808	24,097	31,711	132 %

Oil, Natural Gas and NGL Sales Revenues. Total net revenues for the six months ended June 30, 2018 were $281.5 million, or 185%, higher than total net revenues for the six months ended June 30, 2017. 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 125%, 112% and 197%, respectively, between periods. The oil volume increase resulted primarily from our drilling success in the Delaware Basin, as well as the producing properties acquired in the GMT Acquisition, which added 154 MBbls of net oil production to our first half 2018 results. Since the second quarter 2017, 75 gross wells were placed on production in the Delaware Basin, which added 3,561 MBbls of net oil production. The increase in the Company's operated well count is attributable to the continued ramp up of development drilling activities and a seven-rig drilling program in the first half of 2018. 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. During the first half of 2018, however, our production was made up of 44% natural gas and NGL volumes compared to 42% in the first half of 2017. This change in our commodity mix was due to the significant increase in NGL volumes (up 197%) between periods, which was primarily a result of the main processor of our wet gas switching from ethane-rejection to ethane-recovery. This switch enabled us to recover an increased amount of ethane from our wet gas. The change to recover a higher portion of ethane started in the second quarter of 2018 and was made due to lower gas prices in the Permian Basin and higher ethane prices, which in turn led to stronger ethane processing economics.

In addition to production-related increases in net revenue between periods, there were also significant increases in our average realized sales prices for oil and NGLs in the first half of 2018 compared to the same 2017 period. The average price for oil before the effects of hedging increased 32%, and the average price for NGLs increased 23% between periods. The 32% increase in the average realized oil price was primarily the result of higher NYMEX crude prices between periods (average NYMEX oil prices increased 31%). The overall 23% increase in average realized NGL prices between periods was primarily attributable to higher Mont Belvieu spot prices for plant products. Conversely, the average realized sales price of natural gas decreased by 25% from the first half of 2017 to first half of 2018. This decrease was mainly due to significantly wider gas differentials in the Permian Basin in 2018 due to anticipated pipeline takeaway capacity constraints and lower NYMEX prices between periods (average NYMEX gas prices being 5% lower between periods).

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

	For the Six Months Ended June 30,		Increase/(Decrease)	
	2018	2017	$	%
Operating costs (in thousands):				
Lease operating expenses	$ 35,458	$ 15,551	$ 19,907	128 %
Severance and ad valorem taxes	28,381	7,910	20,471	259 %
Gathering, processing and transportation expenses	29,124	12,647	16,477	130 %
Operating costs per Boe:				
Lease operating expenses	$ 3.51	$ 3.57	$ (0.06)	(2)%
Severance and ad valorem taxes	2.81	1.81	1.00	55 %
Gathering, processing and transportation expenses	2.88	2.90	(0.02)	(1)%

Lease Operating Expenses. LOE for the six months ended June 30, 2018 increased $19.9 million as compared to the six months ended June 30, 2017. Higher LOE for the first half of 2018 was primarily related to a $19.1 million increase in expense associated with a higher well count. We had 217 gross operated horizontal wells as of June 30, 2018 compared to 158 gross operated horizontal wells as of June 30, 2017. The increase in well count was mainly the result of successful drilling activity which added 75 gross operated wells since the second quarter of 2017, which was partially offset by divestiture activity. In addition, workover activity increased $0.8 million between periods as a result of our higher well count.

LOE on a per Boe basis, on the other hand, decreased when comparing the first half of 2018 to the same 2017 period. LOE per Boe was $3.51 for the six months ended June 30, 2018, which represents a decrease of $0.06 per Boe from the comparable 2017 period. This decrease in rate was mainly due to flush production from new wells we drilled and completed over the past 12 months, which has effect of reducing fixed and semi-variable costs on a per Boe basis. This decrease was partially offset by higher costs incurred in the first half of 2018 related to water handling and equipment rentals.

Severance and Ad Valorem Taxes. Severance taxes are primarily based on the market value of our production at the wellhead and 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 taxes for the first half of 2018 increased $14.8 million compared to the same 2017 period primarily due to higher oil, natural gas and NGL revenues between periods. Severance and ad valorem taxes as a percentage of total net revenues increased to 7% for the six months ended June 30, 2018 as compared to 5% in 2017 due to increased ad valorem taxes of $5.7 million between periods, associated with higher well count and higher oil and gas property values.

Gathering, Processing and Transportation Expenses. GP&T for the six months ended June 30, 2018 increased $16.5 million compared to the six months ended June 30, 2017 due to higher natural gas and NGL volumes sold between periods, which in turn resulted in a higher amount of plant processing fees and transportation and gathering costs being incurred between periods.

On a per Boe basis, GP&T decreased 1% from $2.90 for the first half of 2017 to $2.88 per Boe for the first half of 2018. On a natural gas and NGL volume basis (i.e. excluding crude oil barrels) the Boe rate decreased 4% between periods to $6.60 from $6.91 for the first half of 2018 and 2017, respectively. This decrease was primarily the result of lower rates on our primary gas contract due to processing rebates received for new wells connected to the plant.

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

	For the Six Months Ended June 30,	
(in thousands)	**2018**	**2017**
Depreciation, depletion and amortization	$ 140,956	$ 60,460
Depreciation, depletion and amortization per Boe	13.95	13.86

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, 2018, DD&A expense amounted to $141.0 million, an increase of $80.5 million over the same 2017 period. This higher DD&A in 2018 was related to increases in overall production volumes as well as higher DD&A rates between periods, which resulted in $79.2 million and $1.3 million, respectively, of incremental DD&A expense being incurred during the first half of 2018.

DD&A per Boe was $13.95 for the first half of 2018 compared to $13.86 for the same period in 2017. The primary factor contributing to this higher DD&A rate was increased drilling and completion costs incurred for new wells completed and placed on production over the past 12 months.

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

	For the Six Months Ended June 30,	
(in thousands)	**2018**	**2017**
Stock-based compensation expense	$ 870	$ 667
Exploratory dry hole costs	395	—
Geological and geophysical costs	4,049	1,803
Exploration expense	$ 5,314	$ 2,470

Exploration was $5.3 million for the six months ended June 30, 2018 compared to $2.5 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 increased G&G projects and seismic studies of $2.2 million.

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)	**2018**	**2017**
Stock-based compensation expense	$ 8,118	$ 4,928
Cash general and administrative expenses	19,988	17,778
General and administrative expenses	$ 28,106	$ 22,706

G&A expenses for the six months ended June 30, 2018 were $28.1 million compared to $22.7 million for the six months ended June 30, 2017. The higher G&A expenses incurred in 2018 were primarily due to $3.6 million in increased employee salaries and payroll burdens and $3.2 million in higher stock-based compensation compared to the prior year period. G&A personnel costs were substantially higher during the first half of 2018 due to the number of administrative employees increasing from 80 as of June 30, 2017 to 104 as of June 30, 2018. These increases were partially offset by lower professional fees and transaction costs incurred during the first half of 2018 as compared to first half of 2017.

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)	**2018**	**2017**
Credit facility	$ 1,470	$ 903
Senior Notes	10,750	—
Amortization of debt issuance costs	806	214
Interest capitalized	(1,422)	—
Total	$ 11,604	$ 1,117

Interest expense was $10.5 million higher for the six months ended June 30, 2018 compared to the same 2017 period primarily due to the issuance of Senior Notes in November 2017, which was partially offset by capitalized interest.

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)	**2018**	**2017**
Cash derivative settlement gain (loss)	$ 5,524	$ (124)
Non-cash mark-to-market derivative gain	19,016	6,412
Net gain (loss) on derivative instruments	$ 24,540	$ 6,288

Income Tax Expense. During the six months ended June 30, 2018 and 2017, the Company recognized income tax expense amounting to $39.1 million and $9.1 million, respectively. The increase in income tax expense for the six months ended June 30, 2018 as compared to the same period in 2017 was primarily due to an increase in taxable income during the first half of 2018 and the release of $5.1 million of the Company's deferred tax asset valuation allowance in the first half of 2017, partially offset by a lower effective federal tax rate. The enactment of the Jobs Act in December 2017 reduced the corporate tax rate to 21%.

The Company's provision for income taxes for the first half of 2018 differed from the amount that would be provided by applying the statutory U.S. federal tax rate of 21% to pre-tax income because of state income taxes and permanent differences.

Liquidity and Capital Resources

Overview

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

The following table summarizes our capital expenditures incurred for the six months ended June 30, 2018:

(in millions)	**For the Six Months Ended June 30, 2018**
Drilling and completion capital expenditures	$ 344.5
Facilities, infrastructure and other [(1)]	84.5
Land	12.5
Total capital expenditures	$ 441.5

(1) Facilities, infrastructure and other includes $65.0 million of well-level facility costs. In previous years, these costs were presented within drilling and completion capital expenditures. This presentation change was made to conform our drilling and completion capital expenditures to that of our peer group and to also present costs consistently with our 2018 capital expenditure guidance.

We continually evaluate our capital needs and compare them to our capital resources. Our estimated capital expenditure budget for 2018 is $885 million to $1,050 million, of which $710 million to $820 million is related to drilling and completion ("D&C") activity. We expect to fund our capital expenditure budget with cash flows from operations and borrowings under our credit facility. The D&C portion of our 2018 capital budget represents an increase over the $624.1 million of D&C expenditures incurred during 2017. This increased 2018 capital budget is driven by an increase in rig activity from six to seven rigs, the associated increase in wells to be drilled in 2018 versus 2017, and the increase in the number of extended lateral wells to be drilled which require more capital than shorter laterals.

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 these planned capital expenditures 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 2018, we believe that our cash flow from operations 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 the 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 current 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)	**2018**	**2017**
Net cash provided by operating activities	$ 323,902	$ 93,140
Net cash used in investing activities	(433,371)	(595,325)
Net cash provided by financing activities	26,274	368,102

During the six months ended June 30, 2018, we generated $323.9 million of cash from operating activities, an increase of $230.8 million from the same period in 2017. Cash provided by operating activities increased primarily due to higher net income between periods as a result of increased crude oil, natural gas and NGL production volumes, higher realized sales prices for crude oil and NGLs and higher cash derivative settlements. These positive factors were partially offset by higher operating expenses and interest expense during the six months ended June 30, 2018 as compared to the same period in 2017. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on fluctuations in certain expenses between periods.

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

During the six months ended June 30, 2017, cash flows from operating activities and cash on hand were used to finance $198.3 million of drilling and development expenditures, while $333.5 million in net proceeds from the issuance of Class A common shares together with cash on hand, $35.0 million in net borrowings under our credit facility, and proceeds from the sale of oil and gas properties were used to finance $405.2 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, 2018, had a borrowing base of $800.0 million and elected commitments of $600.0 million. The credit agreement provides for a five-year secured revolving credit facility, maturing on May 4, 2023. The Company had $30.0 million borrowings outstanding and $569.1 million in available borrowing capacity, which was net of $0.9 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 each April 1 and October 1 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 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 ranging from 150 to 250 basis points, 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 ranging from 50 to 150 basis points, 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. CRP may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

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, 2018 and through the filing of this Quarterly Report.

5.375% Senior Unsecured Notes due 2026

On November 30, 2017, CRP issued at par $400.0 million of 5.375% senior notes due 2026 (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 Senior Notes semi-annually in arrears on each January 15 and July 15, commencing 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 indenture governing the Senior Notes.

At any time prior to January 15, 2021, CRP may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the 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% of the principal amount of the Senior Notes redeemed, plus any accrued and unpaid interest to the date of redemption; provided that at least 65% of the aggregate principal amount issued under the indenture governing the Senior Notes remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to January 15, 2021, 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 January 15, 2021, CRP may redeem the Senior Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.688% for the 12-month period beginning on January 15, 2021, 101.344% for the 12-month period beginning January 15, 2022, and 100% beginning on January 15, 2023, 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 indenture 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, 2018 and through the filing of this Quarterly Report.

Upon an Event of Default (as defined in the indenture 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.

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, 2017, there have not been any significant, non-routine changes in our contractual obligations, other than additional agreements as discussed in *Note 12—Commitments and Contingencies* 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, 2018 to the methodology applied by management for critical accounting policies previously disclosed in our 2017 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 2017 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

We are exposed to market risk in the form of adverse changes in commodity prices and interest rates 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 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. 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 major 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 2018, our income before income taxes for the six months ended June 30, 2018 would have moved up or down $34.9 million for each 10% change in oil prices per Bbl, $5.2 million for each 10% change in NGL prices per Bbl, and $3.3 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 and 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, 2018 and additional contracts entered into through August 1, 2018. Refer to *Note 7—Derivative Instruments* in Item 1 of Part I of this Quarterly Report for open derivative positions as of June 30, 2018:

	Period	Volume (Bbl)	Volume (Bbls/d)	Weighted Average Differential ($/Bbl) [(1)]
Crude oil basis swaps	July 2018 - September 2018	828,000	9,000	$ (2.38)
	October 2018 - December 2018	828,000	9,000	(2.38)
	January 2019 - March 2019	540,000	6,000	(5.34)
	April 2019 - June 2019	91,000	1,000	(10.00)
	July 2019 - September 2019	1,380,000	15,000	(9.03)
	October 2019 - December 2019	920,000	10,000	(4.24)

(1) The oil basis swap transactions are settled based on the difference between the arithmetic average of the ARGUS MIDLAND WTI and ARGUS WTI CUSHING settlements, during the relevant calculation period.

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Fixed Price ($/MMBtu) (1)
Natural Gas Swaps - Henry Hub	January 2019 - December 2019	10,950,000	30,000	$ 2.78
Natural Gas Swaps - West Texas WAHA	January 2019 - December 2019	5,475,000	15,000	1.61

	Period	Volume (MMBtu)	Volume (MMBtu/d)	Weighted Average Differential ($/MMBtu) (2)
Natural gas basis swaps	July 2018 - December 2018	920,000	5,000	$ (0.43)
	January 2019 - December 2019	12,775,000	35,000	(1.31)

(1) The natural gas swap contracts are settled based on the month's average daily NYMEX price of Henry Hub Natural Gas or Inside FERC's West Texas WAHA price of natural gas.

(2) The natural gas basis swap contracts are settled based on the difference between Inside FERC's West Texas WAHA price of natural gas and the NYMEX price of Natural Gas during the relevant calculation period.

Changes in the fair value of derivative contracts from December 31, 2017 to June 30, 2018, are presented below:

(in thousands)	Commodity derivative contracts
Net fair value of oil and gas derivative contracts outstanding as of December 31, 2017	$ 855
Contracts settled	(334)
Change in the futures curve of forecasted commodity prices	13,607
Contracts added	5,742
Net fair value of oil and gas derivative contracts outstanding as of June 30, 2018	$ 19,870

A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of June 30, 2018 would cause a $3.7 million increase or decrease, respectively, in this fair value asset, and a hypothetical upward or downward shift of 10% per Mcf in the NYMEX forward curve for natural gas as of June 30, 2018 would cause a $2.0 million increase or decrease, respectively, in this fair value asset.

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, 2018, the Company had $30.0 million of debt outstanding under its credit agreement, with a weighted average interest rate of 3.56%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would be approximately $0.3 million per year. We do not currently have or intend to enter into any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

The Company's remaining long-term debt balance of $391.2 million consists of our Senior Notes, which has a fixed interest rate; therefore, this balance is not affected by interest rate movements. For additional information regarding the Company's debt instruments, see *Note 4—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 our 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, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us 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, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the three months ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls 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 2017 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 2017 Annual Report or our other SEC filings.

Item 6. Exhibits.

Exhibit Number	Description of Exhibit
3.1	Second Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on October 11, 2016).
3.2	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on October 7, 2016).
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 Registrant'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 Registrant'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 Registrant'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.
10.1	Second Amended and Restated Credit Agreement, dated as of May 4, 2018, among Centennial Resource Production, LLC, as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 7, 2018).
10.2	Purchase and Sale Agreement, dated as of August 2, 2018, between Centennial Resource Production, LLC and BP North America Inc. (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 6, 2018).
10.3*#	Amended and Restated Non-Employee Director Compensation Program.
10.4*#	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*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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
Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)

Date: August 6, 2018

Exhibit 3.6

AMENDMENT NO. 3 TO
FIFTH AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT
OF CENTENNIAL RESOURCE PRODUCTION, LLC

This Amendment No. 3 (this "***Amendment***") to the Fifth Amended and Restated Limited Liability Company Agreement of Centennial Resource Production, LLC, dated as of October 11, 2016, as amended by Amendment No. 1 thereto, dated as of December 28, 2016, and Amendment No. 2 thereto, dated as of March 20, 2017 (as amended to date, the "***Agreement***"), is entered into as of June 15, 2018 by Centennial Resource Production, LLC, a Delaware limited liability company (the "***Company***"), and Centennial Resource Development, Inc., a Delaware corporation and sole manager of the Company (the "***Corporation***" or, in its capacity as the sole manager of the Company, the "***Manager***"). Capitalized terms used but not defined herein have the meaning given such terms in the Agreement.

WHEREAS, in connection with the closing of the transactions contemplated by those certain Subscription Agreements, each dated as of May 4, 2017, by and between the Corporation and certain investors named therein (collectively, the "***Investors***"), the Corporation issued to such Investors an aggregate of 33,012,380 shares of Class A Common Stock, in exchange for gross proceeds of approximately $341 million (the "***PIPE Proceeds***");

WHEREAS, on May 25, 2017, the 104,400 Series B Preferred Units owned by the Corporation converted into 26,100,000 Common Units in accordance with their terms (the "***Series B Conversion***");

WHEREAS, on November 7, 2017, pursuant to Article XI of the Agreement and as permitted under Article X, Celero Energy Company, LP, a Delaware limited partnership and member of the Company ("***Celero***"), caused the Company to redeem 3,494,583 Common Units (the "***2017 Redemption***");

WHEREAS, on March 5, 2018, pursuant to Article XI of the Agreement and as permitted under Article X, Celero, Centennial Resource Development, LLC, a Delaware limited liability company and member of the Company ("***CRD***"), and NGP Centennial Follow-On LLC, a Delaware limited liability company and member of the Company ("***NGP Follow-On***"), caused the Company to redeem Common Units in the following amounts: (a) Celero – 752,315 Common Units; (b) CRD – 2,128,462 Common Units and (c) NGP Follow-On – 466,870 Common Units (the "***2018 Redemption***");

WHEREAS, on June 15, 2018, in connection with its liquidation and as permitted under Section 10.02(ii) of the Agreement, CRD transferred all of its Common Units (the "***CRD Transfer***") to the holders of equity interests in CRD (the "***CRD Transferees***") and such CRD Transferees have entered into a Joinder;

WHEREAS, under Section 10.07 of the Agreement, the Manager shall promptly amend the Schedule of Members to reflect any Permitted Transfer pursuant to Article X of the Agreement; and

WHEREAS, the Manager desires to enter into this Amendment, in accordance with Section 10.07 and Section 16.03 of the Agreement, to update the Schedule of Members to reflect the contribution by the Corporation of the PIPE Proceeds to the Company as a Capital Contribution, the Series B Conversion, the 2017 Redemption, the 2018 Redemption and the CRD Transfer.

NOW, THEREFORE, the Company and the Manager hereby enter into this Amendment to provide as follows:

Section 1. Amendments. Schedule 1 to the Agreement shall be amended and restated in its entirety and replaced with Schedule 1 to this Amendment.

Section 2. Binding Effect; Intended Beneficiaries. This Amendment shall be binding upon and inure to the benefit of the Company, the Members and their respective heirs, executors, administrators, successors, legal representatives and permitted assigns.

Section 3. Counterparts. This Amendment may be executed in separate counterparts, each of which will be an original and all of which together shall constitute one and the same agreement binding on all the parties hereto.

Section 4. Applicable Law. This Amendment shall be governed by, and construed in accordance with, the laws of the State of Delaware, without giving effect to any choice of law or conflict of law rules or provisions (whether of the State of Delaware or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of Delaware. Any dispute relating hereto shall be heard in the state or federal courts of the State of Delaware, and the parties agree to jurisdiction and venue therein.

Section 5. Effectiveness. Except as hereby amended, the Agreement shall remain in full force and effect.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the undersigned has executed or caused to be executed on its behalf this Amendment No. 3 to Fifth Amended and Restated Limited Liability Company Agreement as of the date first written above.

COMPANY:

CENTENNIAL RESOURCE PRODUCTION, LLC

By: /s/ George S. Glyphis
Name: George S. Glyphis
Title: Vice President, Chief Financial Officer and Secretary

MANAGER:

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ Mark G. Papa
Name: Mark G. Papa
Title: Chief Executive Officer

SCHEDULE 1

SCHEDULE OF MEMBERS

The Schedule of Members is on file with the Company.

Exhibit 10.3

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

Effective Date: August 1, 2018

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) $162,500 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 $162,500 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***."

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 Policy 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.

* *

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:	[__________]
Performance Period:	July 1, 2018 through June 30, 2021
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.

* * * * *

Appendix A

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.

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

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

Cimarex Energy Co.	Matador Resources Company
PDC Energy, Inc.	WPX Energy, Inc.
Energen Corporation	Parsley Energy, Inc.
QEP Resources, Inc.	Callon Petroleum Company
Diamondback Energy, Inc.	Laredo Petroleum, Inc.
SM Energy Company	

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	90.9%	182%
3	81.8%	164%
4	72.7%	145%
5	63.6%	127%
6	54.6%	109%
7	45.5%	91%
8	36.4%	68%
9	27.3%	45%
10	18.2%	0%
11	9.1%	0%
12	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.

* * * * *

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 6, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

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

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 6, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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

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, 2018 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 6, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ MARK G. PAPA

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

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, 2018 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 6, 2018

CENTENNIAL RESOURCE DEVELOPMENT, INC.

By: /s/ GEORGE S. GLYPHIS

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