Filed Pursuant to Rule 424(b)(3)
Registration No. 333-228740

PROSPECTUS SUPPLEMENT NO. 3
(to prospectus dated March 12, 2019)

51,819,725 Shares

Berry Petroleum Corporation

Common Stock

This prospectus supplement is being filed to update and supplement information contained in the prospectus dated March 12, 2019, as amended and supplemented from time to time, covering the offer and resale of our common stock by the selling stockholders identified in the prospectus, or their permitted transferees, with information contained in our Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on August 8, 2019.

This prospectus supplement updates and supplements the information in the prospectus and is not complete without, and may not be delivered or utilized except in combination with, the prospectus, including any amendments or supplements thereto. This prospectus supplement should be read in conjunction with the prospectus and if there is any inconsistency between the information in the prospectus and this prospectus supplement, you should rely on the information in this prospectus supplement.

Investing in our common stock involves risks. Please see "Risk Factors" beginning on page 5 of the prospectus.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus supplement is August 8, 2019

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

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2019
OR

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

For the transition period from_______________ to _______________
Commission file number 001-38606

BERRY PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**81-5410470**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

16000 Dallas Parkway, Suite 500
Dallas, Texas 75248
(661) 616-3900
(Address of principal executive offices, including zip code
Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value $0.001 per share	BRY	Nasdaq Global Select Market

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or emerging growth company. See 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 x	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 Act). Yes ☐ No ☒

Shares of common stock outstanding as of July 31, 2019 80,973,285

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The financial information and certain other information presented in this Form 10-Q have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables. In addition, certain percentages presented here reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2019	December 31, 2018
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 227	$ 68,680
Accounts receivable, net of allowance for doubtful accounts of $1,377 at June 30, 2019 and $950 at December 31, 2018	54,871	57,379
Derivative instruments	29,945	88,596
Other current assets	22,250	14,367
Total current assets	107,293	229,022
Noncurrent assets:		
Oil and natural gas properties	1,581,035	1,461,993
Accumulated depletion and amortization	(163,948)	(123,217)
Total oil and natural gas properties, net	1,417,087	1,338,776
Other property and equipment	129,190	119,710
Accumulated depreciation	(20,273)	(15,778)
Total other property and equipment, net	108,917	103,932
Derivative instruments	8,282	3,289
Other non-current assets	15,162	17,244
Total assets	$ 1,656,741	$ 1,692,263
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 127,110	$ 144,118
Derivative instruments	7,409	—
Total current liabilities	134,519	144,118
Noncurrent liabilities:		
Long-term debt	397,315	391,786
Derivative instruments	206	—
Deferred income taxes	44,946	45,835
Asset retirement obligation	102,291	89,176
Other noncurrent liabilities	25,148	14,902
Commitments and Contingencies - Note 4		
Equity:		
Common stock ($.001 par value; 750,000,000 shares authorized; and 80,973,285 and 81,202,437 shares outstanding, at June 30, 2019 and December 31, 2018, respectively)	85	82
Additional paid-in-capital	897,322	914,540
Treasury stock, at cost, (3,648,823 shares at June 30, 2019 and 448,661 shares at December 31, 2018)	(39,225)	(24,218)
Retained earnings	94,134	116,042
Total equity	952,316	1,006,446
Total liabilities and equity	$ 1,656,741	$ 1,692,263

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 136,908	$ 137,385	$ 268,010	$ 263,010
Electricity sales	5,364	5,971	15,093	11,423
Gains (losses) on oil derivatives	27,276	(78,143)	(37,963)	(112,787)
Marketing revenues	414	518	1,244	1,302
Other revenues	104	251	221	317
Total revenues and other	170,066	65,982	246,605	163,265
Expenses and other:				
Lease operating expenses	47,879	41,517	105,807	85,819
Electricity generation expenses	3,164	3,135	10,924	7,725
Transportation expenses	1,694	2,343	3,867	5,321
Marketing expenses	421	407	1,272	987
General and administrative expenses	16,158	12,482	30,498	24,466
Depreciation, depletion, and amortization	23,654	21,859	48,240	40,288
Taxes, other than income taxes	11,348	8,715	19,434	16,972
Losses on natural gas derivatives	9,449	—	7,334	—
Other operating expenses	3,119	123	4,364	123
Total expenses and other	116,886	90,581	231,740	181,701
Other income (expenses):				
Interest expense	(8,961)	(9,155)	(17,766)	(16,951)
Other, net	—	(239)	155	(212)
Total other income (expenses)	(8,961)	(9,394)	(17,611)	(17,163)
Reorganization items, net	(26)	456	(257)	9,411
Income (loss) before income taxes	44,193	(33,537)	(3,003)	(26,188)
Income tax expense (benefit)	12,221	(5,476)	(877)	(4,537)
Net income (loss)	31,972	(28,061)	(2,126)	(21,651)
Series A preferred stock dividends	—	(5,650)	—	(11,301)
Net income (loss) attributable to common stockholders	$ 31,972	$ (33,711)	$ (2,126)	$ (32,952)
Net income (loss) per share attributable to common stockholders:				
Basic	$ 0.39	$ (0.94)	$ (0.03)	$ (0.89)
Diluted	$ 0.39	$ (0.94)	$ (0.03)	$ (0.89)

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Six-Month Period Ended June 30, 2018					
	Series A Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
December 31, 2017	$ 335,000	$ 33	$ 545,345	$ —	$ (21,068)	$ 859,310
Stock based compensation	—	—	1,042	—	—	1,042
Cash dividends declared on Series A preferred stock, $0.158/share	—	—	(5,650)	—	—	(5,650)
Net income (loss)	—	—	—	—	6,410	6,410
March 31, 2018	335,000	33	540,737	—	(14,658)	861,112
Stock based compensation	—	—	1,278	—	—	$ 1,278
Shares withheld for payment of taxes on equity awards	—	—	(176)	—	—	$ (176)
Cash dividends declared on Series A preferred stock, $0.15/share	—	—	(5,651)	—	—	$ (5,651)
Purchase of rights to common stock	—	—	—	(20,006)	—	$ (20,006)
Net income (loss)	—	—	—	—	(28,061)	$ (28,061)
June 30, 2018	$ 335,000	$ 33	$ 536,188	$ (20,006)	$ (42,719)	$ 808,496

	Six-Month Period Ended June 30, 2019					
	Series A Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
December 31, 2018	$ —	$ 82	$ 914,540	$ (24,218)	$ 116,042	$ 1,006,446
Shares withheld for payment of taxes on equity awards and other	—	—	(270)	—	—	(270)
Stock based compensation	—	—	1,498	—	—	1,498
Purchases of treasury stock	—	—	—	(24,375)	—	(24,375)
Purchase of rights to common stock(1)	—	—	(20,265)	20,265	—	—
Common stock issued to settle unsecured claims	—	3	(3)	—	—	—
Dividends declared on common stock, $0.12/share	—	—	—	—	(10,072)	(10,072)
Net income (loss)	—	—	—	—	(34,098)	(34,098)
March 31, 2019	—	85	895,500	(28,328)	71,872	939,129
Shares withheld for payment of taxes on equity awards and other	—	—	(675)	—	—	(675)
Stock based compensation	—	—	2,497	—	—	2,497
Purchases of treasury stock	—	—	—	(10,897)	—	(10,897)
Dividends declared on common stock, $0.12/share	—	—	—	—	(9,710)	(9,710)
Net income (loss)	—	—	—	—	31,972	31,972
June 30, 2019	$ —	$ 85	$ 897,322	$ (39,225)	$ 94,134	$ 952,316

(1) In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. We paid approximately $20 million to purchase their claims to our common stock. These claims were settled in February 2019 with no shares issued.

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

BERRY PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2019	2018
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (2,126)	$ (21,651)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	48,240	40,288
Amortization of debt issuance costs	2,517	2,651
Stock-based compensation expense	3,918	2,320
Deferred income taxes	(877)	(4,537)
Increase (decrease) in allowance for doubtful accounts	427	(20)
Other operating expenses	395	123
Reorganization expenses, net (non-cash)	—	(10,763)
Derivative activities:		
Total losses	45,297	112,787
Cash settlements on derivatives	11,578	(46,110)
Cash payments on early-terminated derivatives	—	(126,949)
Changes in assets and liabilities:		
Decrease (increase) in accounts receivable	2,108	(2,120)
(Increase) in other assets	(13,021)	(1,859)
(Decrease) increase in accounts payable and accrued expenses	(8,319)	8,421
(Decrease) in other liabilities	336	(2,129)
Net cash provided by (used in) operating activities	90,473	(49,548)
Cash flows from investing activities:		
Capital expenditures:		
Development of oil and natural gas properties	(95,538)	(37,609)
Purchases of other property and equipment	(9,190)	(7,760)
Acquisition of properties	(2,689)	—
Proceeds from sale of property and equipment and other	38	3,022
Net cash (used in) investing activities	(107,379)	(42,347)
Cash flows from financing activities:		
Borrowings under RBL credit facility	123,400	96,800
Repayments on RBL credit facility	(118,200)	(409,800)
Proceeds from issuance of senior unsecured notes	—	400,000
Dividends paid on common stock	(19,662)	—
Purchase of treasury stock	(36,139)	(20,006)
Shares withheld for payment of taxes on equity awards and other	(946)	(176)
Dividends paid on Series A Preferred Stock	—	(11,301)
Debt issuance costs	—	(9,050)
Net cash (used in) provided by financing activities	(51,547)	46,467
Net decrease in cash, cash equivalents and restricted cash	(68,453)	(45,428)
Cash, cash equivalents and restricted cash:		
Beginning	68,680	68,738
Ending	$ 227	$ 23,310

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

Note 1 - Basis of Presentation

“Berry Corp.” refers to Berry Petroleum Corporation, a Delaware corporation, which is the sole member of Berry Petroleum Company, LLC ("Berry LLC").

As the context may require, the “Company”, “we”, “our” or similar words refer to (i) Berry Corp. and Berry LLC, its consolidated subsidiary, as a whole or (ii) either Berry Corp. or Berry LLC.

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located in the United States (the “U.S.”), in California (in the San Joaquin and Ventura basins), Utah (in the Uinta basin), and Colorado (in the Piceance basin).

Principles of Consolidation and Reporting

The condensed consolidated financial statements were prepared in conformity with U.S. generally accepted accounting principles ("GAAP"), which requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. In management’s opinion, the accompanying financial statements contain all normal, recurring adjustments that are necessary to fairly present our interim unaudited condensed consolidated financial statements as of June 30, 2019. We eliminated all significant intercompany transactions and balances upon consolidation. For oil and gas exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

We prepared this report pursuant to the rules and regulations of the U.S. Security and Exchange Commission ("SEC") applicable to interim financial information, which permit the omission of certain disclosures to the extent they have not changed materially since the latest annual financial statements. We believe our disclosures are adequate to make the disclosed information not misleading. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This Form 10-Q should be read in conjunction with the consolidated financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2018.

Recently Adopted Accounting Standards

During 2016, the FASB issued rules clarifying the new revenue recognition standard issued in 2014. The new rules are intended to improve and converge the financial reporting requirements for revenue from contracts with customers. We are an emerging growth company and elected to delay adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 31, 2018. As such, we adopted these rules in the first quarter of 2019 and applied the modified retrospective approach, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. We have performed an analysis of existing contracts and determined adoption did not have a material impact on our condensed consolidated financial statements. In addition, we have evaluated the changes to relevant business practices, accounting policies and control activities and we did not experience a material change in our revenue accounting as a result of the adoption of these rules. Refer to Note 8 for additional disclosure information.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and do not expect a material impact on our consolidated results of operations.

Note 2 - Debt

The following table summarizes our outstanding debt:

	June 30, 2019	December 31, 2018	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ 5,200	$ —	variable rates of 6.25% (2019) and 4.5% (2018), respectively	June 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on other assets
2026 Senior Unsecured Notes	400,000	400,000	7.00%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	405,200	400,000			
Less: Debt Issuance Costs	(7,885)	(8,214)			
Long-Term Debt, net	$ 397,315	$ 391,786			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At June 30, 2019 and December 31, 2018, debt issuance costs for the RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $13 million and $16 million net of amortization, respectively. The amortization of debt issuance costs is presented in interest expense on the condensed consolidated statements of operations. At June 30, 2019 and December 31, 2018, debt issuance costs, net of amortization, for the 2026 Senior Unsecured Notes were both $8 million.

For the three months ended June 30, 2019 and June 30, 2018, the amortization expense for the RBL Facility and 2026 Senior Unsecured Notes was approximately $1 million, which was included in "interest expense" in the condensed consolidated statements of operations. For the six months ended June 30, 2019 and June 30, 2018, these amounts were approximately $3 million, which was included in “interest expense” in the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amount of the RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 senior unsecured notes was approximately $388 million and $368 million at June 30, 2019 and December 31, 2018, respectively.

The RBL Facility

On July 31, 2017, we entered into a credit agreement (“RBL Facility”), with Wells Fargo Bank, N.A. as administrative agent and certain lenders with up to $1.5 billion of commitments, subject to a reserves-based borrowing base. In April 2019, we completed a borrowing base redetermination under our RBL Facility that resulted in our borrowing base being set at $750 million and we reaffirmed our elected commitment amount at $400 million. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

We were in compliance with all financial covenants as of June 30, 2019.

As of June 30, 2019, we had approximately $386 million of available borrowing capacity under the RBL Facility.

As of June 30, 2019 and December 31, 2018, we had letters of credit outstanding of approximately $9 million and $7 million, respectively, under our RBL facility. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters.

Note 3 - Derivatives

We utilize derivatives, such as swaps, puts, and calls to hedge a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices. We target covering our operating expenses and fixed charges, including maintenance capital expenditures, interest and dividends, with the oil hedges for a period of up to two years out. We have hedged a portion of our exposure to differentials between ICE Brent oil (“Brent”) and NYMEX West Texas Intermediate oil (“WTI”) as well. Additionally, we target fixing the price for a large portion of our natural gas purchases used in our steam operations for up to two years. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations, which we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

As of June 30, 2019, our hedge position consisted of oil swaps, puts and calls, and natural gas swaps. We use oil swaps and puts to protect against decreases in the oil price and natural gas swaps to protect against increases in natural gas prices. We do not enter into derivative contracts for speculative trading purposes and have not accounted for our derivatives as cash-flow or fair-value hedges. We did not designate any of our contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil hedges are classified in the revenues and other section of the condensed consolidated statements of operations and (gains) losses on natural gas hedges are presented in the expenses and other section of the condensed consolidated statements of operations.

As of June 30, 2019, we had the following crude oil production and gas purchases hedges.

	Q3 2019	Q4 2019	FY 2020
Sold Oil Calls Options (Brent):			
Hedged volume (MBbls)	92	92	—
Weighted-average price ($/Bbl)	$ 81.00	$ 81.00	$ —
Purchased Oil Put Options (Brent):			
Hedged volume (MBbls)	460	460	—
Weighted-average price ($/Bbl)	$ 50.00	$ 50.00	$ —
Fixed Price Oil Swaps (Brent):			
Hedged volume (MBbls)	1,472	1,380	4,392
Weighted-average price ($/Bbl)	$ 72.64	$ 72.21	$ 65.70
Fixed Price Oil Swaps (WTI):			
Hedged volume (MBbls)	92	92	121
Weighted-average price ($/Bbl)	$ 61.75	$ 61.75	$ 61.75
Oil basis differential positions (Brent-WTI basis swaps):			
Hedged volume (MBbls)	46	46	—
Weighted-average price ($/Bbl)	$ (1.29)	$ (1.29)	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	4,600,000	4,295,000	13,725,000
Weighted-average price ($/MMBtu)	$ 2.91	$ 2.95	$ 2.98
Fixed Price Gas Purchase Swaps (SoCal Citygate):			
Hedged volume (MMBtu)	460,000	460,000	1,525,000
Weighted-average price ($/MMBtu)	$ 3.80	$ 3.80	$ 3.80

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our purchased puts we paid a premium at the time the positions were created and for others, the premium payment is deferred until the time of settlement. We have mitigated the exposure to a substantial portion of these premium payments by entering into offsetting put positions. We paid approximately $4 million and $19 million of the deferred premiums during the three and six months ended June 30, 2019, which is partially offset by premiums received during the six months ended June 30, 2019. The remaining deferred premiums of approximately $2 million are reflected in the mark-to-market valuation and will be payable through the first quarter of 2020.

For fixed-price swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent or WTI and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent or WTI.

For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel of our contracts and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel.

For fixed-price natural gas purchase swaps, we are the buyer so we make settlement payments for prices below the weighted-average price per MMBtu and receive settlement payments for prices above the weighted-average price per MMBtu.

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including publicly available underlying commodity prices and forward curves, and all are classified as Level 2 in the required fair value hierarchy for the periods presented. These commodity derivatives are subject to counterparty netting. The following tables present the fair values (gross and net) of our outstanding derivatives as of June 30, 2019 and December 31, 2018:

	June 30, 2019			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 39,116	$ (9,172)	$ 29,945
Commodity Contracts	Non-current assets	9,301	(1,020)	8,282
Liabilities:				
Commodity Contracts	Current liabilities	(16,581)	9,172	(7,409)
Commodity Contracts	Non-current liabilities	(1,226)	1,020	(206)
Total derivatives		$ 30,611	$ —	$ 30,611

	December 31, 2018			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 89,981	$ (1,385)	$ 88,596
Commodity Contracts	Non-current assets	3,289	—	3,289
Liabilities:				
Commodity Contracts	Current liabilities	(1,385)	1,385	—
Total derivatives		$ 91,885	$ —	$ 91,885

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. We do not receive collateral from our counterparties.

We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standards & Poor's or Moody's, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which partially mitigates the counterparty nonperformance risk.

Note 4 - Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at June 30, 2019 and December 31, 2018. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of June 30, 2019, we are not aware of material indemnity claims pending or threatened against us.

During the six months ended June 30, 2019, we entered into agreements to replace our Bakersfield, California office lease for approximately $11 million in aggregate over 8 years beginning August 2019. The annual costs under our current office lease, which ends in 2019, are similar to the costs under the new leases.

Note 5 - Equity

Cash Dividends

Our board of directors approved $0.12 per share quarterly cash dividends on our common stock for the first, second and third quarters of 2019. We paid the second quarter dividend in July 2019 and declared the third quarter dividend in July 2019, which is payable in October 2019.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board’s evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Petroleum to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. For the three months ended June 30, 2019, we repurchased 1,000,000 shares at an average price of $10.90 per share for $11 million, which is reflected as treasury stock. For the six months ended June 30, 2019, we repurchased 3,200,162 shares at an average price of $11.02 per share for $35 million, which is reflected as treasury stock. The Company has repurchased a total of 3,648,823 shares under the stock repurchase program for $39 million as of June 30, 2019.

Stock-Based Compensation

In March 2019, the Company granted awards of 706,314 shares of restricted stock units ("RSUs"), which will vest annually in equal amounts over three years and 553,902 performance-based restricted stock units ("PSUs"), which will cliff vest at two or three years. The fair value of these awards was approximately $16 million.

The RSUs awarded are service-based awards. The PSUs awarded include a market objective measured against both absolute total stockholder return (“Absolute TSR”) and total stockholder return relative (“Relative TSR”), to the Vanguard World Fund - Vanguard Energy ETF index (the “Index”) over the performance period, assuming the reinvestment of dividends. Depending on the results achieved during the two or three year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 200% of the Target Shares granted.

The fair value of the PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Index over the performance periods. The expected volatility of the Company’s common stock at the date of grant was estimated based on blended historical average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the current annualized declared dividend.

The risk-free interest rate assumption was based on observed interest rates consistent with the approximate two and three year performance measurement period.

Note 6 - Supplemental Disclosures to the Financial Statements

Other current assets reported on the condensed consolidated balance sheets included the following:

	June 30, 2019	December 31, 2018
	(in thousands)	
Prepaid expenses	$ 7,382	$ 4,656
Materials and supplies	10,909	5,461
Inventories	3,717	4,012
Other	243	238
Total	$ 22,250	$ 14,367

The major classes of inventory were not material and therefore not stated separately. Other non-current assets at June 30, 2019 and December 31, 2018, included approximately $13 million and $16 million of deferred financing costs, net of amortization, respectively.

Accounts payable and accrued expenses on the condensed consolidated balance sheets included the following:

	June 30, 2019	December 31, 2018
	(in thousands)	
Accounts payable-trade	$ 20,693	$ 13,564
Accrued expenses	52,070	66,417
Royalties payable	16,160	26,189
Taxes other than income tax liability	8,526	10,766
Accrued interest	10,516	10,500
Dividends payable	10,112	9,992
Asset retirement obligation - current portion	8,927	6,372
Other	106	318
Accounts payable and accrued expenses - total	$ 127,110	$ 144,118

The increase in the long-term portion of the asset retirement obligation largely reflected an increase in the change in estimate of $18 million, $2 million in new wells, and accretion expense of $3 million. The change in estimate was a result of California's new idle well regulations effective in the second quarter. This accelerated the timing of abandonment of certain wells. These increases were partially offset by liabilities settled during the period of $8 million and an increase to the current portion of the asset retirement obligation of $3 million.

Other non-current liabilities at June 30, 2019 and December 31, 2018 included approximately $25 million and $15 million of greenhouse gas liability, respectively.

Supplemental Information on the Statement of Operations

Other operating expenses mainly consist of excess abandonment costs, as well as gain (loss) on sale of assets.

Supplemental Cash Flow Information

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Six Months Ended June 30,	
	2019	2018
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
(Increase) decrease in accrued liabilities related to purchases of property and equipment	$ 3,938	$ 8,614
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 15,272	$ 3,298
Reorganization items, net	$ —	$ 1,352

The following table provides a reconciliation of cash, cash equivalents and restricted cash as reported in the condensed consolidated statements of cash flows to the line items within the condensed consolidated balance sheets:

	Six Months Ended June 30,	
	2019	2018
	(in thousands)	
Beginning of Period		
Cash and cash equivalents	$ 68,680	$ 33,905
Restricted cash	—	34,833
Cash, cash equivalents and restricted cash	$ 68,680	$ 68,738
Ending of Period		
Cash and cash equivalents	$ 227	$ 3,600
Restricted cash	—	19,710
Cash, cash equivalents and restricted cash	$ 227	$ 23,310

Restricted cash was associated with cash reserved to settle claims with general unsecured creditors. Cash and cash equivalents consist primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value.

Note 7 - Earnings Per Share

We calculate basic earnings (loss) per share by dividing net income (loss) attributable to common stockholders by the weighted-average number of common shares outstanding during each period, which is approximately 82 million shares in 2019. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, are considered common shares outstanding and are included in the computation of net income (loss) per share. Our initial capitalization included the issuance of 32,920,000 shares of common stock and another 7,080,000 shares reserved to settle claims of unsecured creditors, all of which were included in our computation of net income (loss) per share until the claims were settled and the shares issued. At the end of February 2019, we finalized settlement of these claims and issued approximately 2,770,000 shares. In all prior periods presented we retrospectively adjusted the weighted average shares in our earnings per share calculations for the ultimate shares issued, instead of the 7,080,000 shares that had been reserved.

The Series A Preferred Stock was not a participating security, therefore, we calculated diluted EPS using the “if-converted" method under which the preferred dividends are added back to the numerator and the convertible preferred stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock were included in the diluted EPS calculation for the three and six months ended June 30, 2019, as all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock in July 2018. No Series A Preferred Stock were included in the diluted EPS calculation for the three and six months ended June 30, 2018 as their effect was anti-dilutive under the "if converted" method. The RSUs are not a participating security as the dividends are forfeitable. We included 164,000 incremental RSU shares in the diluted EPS calculation for the three months ended June 30, 2019. No incremental RSU shares were included in the diluted EPS calculation for the six months ended June 30, 2019 and the three and six months ended June 30, 2018, as their effect was anti-dilutive under the "if-converted" method. No PSU's were included in the EPS calculations for any of the periods presented due to their contingent nature.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands except per share amounts)			
Basic EPS calculation				
Net income (loss)	$ 31,972	$ (28,061)	$ (2,126)	(21,651)
less: Series A Preferred Stock dividends and conversion to common stock	—	(5,650)	—	(11,301)
Net income (loss) attributable to common stockholders	$ 31,972	$ (33,711)	$ (2,126)	$ (32,952)
Weighted-average shares of common stock outstanding	81,519	35,873	82,061	37,224
Basic earnings (loss) per share(2)	$ 0.39	$ (0.94)	$ (0.03)	$ (0.89)
Diluted EPS calculation				
Net income (loss)	$ 31,972	$ (28,061)	$ (2,126)	$ (21,651)
less: Series A Preferred Stock dividends and conversion to common stock	—	(5,650)	—	(11,301)
Net income (loss) attributable to common stockholders	$ 31,972	$ (33,711)	$ (2,126)	$ (32,952)
Weighted-average shares of common stock outstanding	81,519	35,873	82,061	37,224
Dilutive effect of potentially dilutive securities(1)	164	—	—	—
Weighted-average common shares outstanding - diluted	81,683	35,873	82,061	37,224
Diluted earnings (loss) per share(2)	$ 0.39	$ (0.94)	$ (0.03)	$ (0.89)

(1) No potentially dilutive securities were included in computing earnings (loss) per share for the six months ended June 30, 2019 and the three and six months ended June 30, 2018, because the effect of inclusion would have been anti-dilutive.

Note 8 - Revenue Recognition

We account for revenue in accordance with the Accounting Standards Codification 606, Revenue from Contracts with Customers, which we adopted on January 1, 2019, using the modified retrospective method, which was applied to all contracts that were not completed as of that date. Prior period results were not adjusted and continue to be reported under the accounting standards in effect for the prior period. The new standard did not affect the timing of our revenue recognition and did not impact net income; accordingly, we did not record an adjustment to the opening balance of retained earnings.

We adopted the practical expedient related to disclosing the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied at the end of the reporting period. The performance obligations that are unsatisfied at the end of a reporting period relate solely to future volumes that we have yet to sell. As such, these are wholly unsatisfied performance obligations as each unit of product represents a separate performance obligation as well as a wholly unsatisfied promise to transfer a distinct good that forms part of a single performance obligation.

We derive substantially all of our revenue from sales of oil, natural gas and natural gas liquids ("NGL"), with the remaining revenue generated from sales of electricity and marketing activities.

The following is a description of our principal activities from which we generate revenue. Revenues are recognized when a customer obtains control of promised goods or services, in an amount that reflects the consideration we expect to receive in exchange for those goods or services.

BERRY PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Oil, Natural Gas and NGLs

We recognize revenue from the sale of our oil, natural gas and NGLs production when delivery has occurred and control passes to the customer. Our oil and natural gas contracts are short term, typically less than a year and our NGL contracts are both short and long term. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Our commodity sales contracts are indexed to a market price or an average index price. We recognize revenue in the amount that we have a right to invoice once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity Sales

The electrical output of our cogeneration facilities that is not used in our operations is sold to the California market based on market pricing, which includes capacity payments. The majority of the portion sold from three of our cogeneration facilities is sold under long-term contracts to two California utility companies, based on the market pricing. Revenue is recognized over time when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on average index pricing with payment due the month following delivery. Capacity payments are based on a fixed annual amount per kilowatt hour and monthly rates vary based on seasonality, which is consistent with how we earn the capacity payment. Capacity payments are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments. We report electricity revenue as electricity sales on our consolidated statements of operations.

Marketing Revenue

Marketing revenue primarily includes our activities associated with transporting and marketing third-party volumes. These sales are made under the same agreements with the same purchaser as our natural gas sales discussed above. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Revenues are presented excluding costs incurred prior to transferring control of these volumes to the customer, or the costs to purchase these volumes when we are acting as the principal. The revenues and expenses related to the sale and purchase of third-party volumes are presented separately as marketing revenue and marketing expenses on the condensed consolidated statements of operations.

Disaggregated Revenue

As a result of adoption of this standard, we are now required to disclose the following information regarding revenue from contracts with customers on a disaggregated basis.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Oil sales	$ 132,165	$ 130,464	$ 255,616	$ 248,367
Natural gas sales	4,086	5,400	10,800	11,963
Natural gas liquids sales	657	1,521	1,594	2,680
Electricity sales	5,364	5,971	15,093	11,423
Marketing revenues	414	518	1,244	1,302
Revenues from contracts with customers	142,686	143,874	284,347	275,735
Gains (losses) on oil derivatives	27,276	(78,143)	(37,963)	(112,787)
Other revenues	104	251	221	317
Total revenues and other	$ 170,066	$ 65,982	$ 246,605	$ 163,265

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

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our interim unaudited consolidated financial statements and related notes presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2018 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"). When we use the terms "we," "us," "our," the "Company" or similar words in this report, we are referring to Berry Corp. and its subsidiary, Berry LLC.

Our Company

We are a western United States independent upstream energy company with a focus on low risk, long-lived, oil reserves in conventional reservoirs. Most of our assets are in the San Joaquin basin of California. Our long-lived, high-margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive levered free cash flow through commodity price cycles. We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and, to a lesser extent, our Rockies assets including low-cost, oil-rich reservoirs in the Uinta basin of Utah and low geologic risk natural gas resource plays in the Piceance basin in Colorado. Successful execution of our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient, consistent and predictable production growth, as well as the ability to continue returning capital to our stockholders.

How We Plan and Evaluate Operations

We use Levered Free Cash Flow to plan our capital allocation for maintenance and internal growth opportunities as well as hedging needs. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) operating expenses; (c) environmental, health & safety ("EH&S") results; (d) cash general and administrative expenses; and (e) production.

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of our business. We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items.

Operating expenses

We define operating expenses as lease operating expenses, electricity generation expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Taxes other than income taxes are excluded from operating expenses. The electricity, transportation and marketing activity related revenues are viewed and treated internally as a reduction to operating costs when tracking and analyzing the economics of development projects and the efficiency of our hydrocarbon recovery. Additionally, we strive to minimize the variability of our fuel gas costs for our steam operations, and we significantly increased our gas hedges in the second quarter of 2019. Overall, operating expense is used by management as a measure of the efficiency with which operations are performing.

Environmental, health & safety

We are committed to good corporate citizenship in our communities, operating safely and protecting the environment and our employees. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics is a part of our incentive programs for all employees.

General and administrative expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

Oil and gas production is a key driver of our operating performance, an important factor to the success of our business, and used in forecasting future development economics. We measure and closely monitor production on a continuous basis, adjusting our property development efforts in accordance with the results. We track production by commodity type and compare it to prior periods and expected results.

Capital Expenditures

As of the three and six months ended June 30, 2019, our capital expenditures for 2019 were approximately $57 million and $106 million, respectively, on an accrual basis excluding acquisitions. For the three and six months ended June 30, 2019, approximately 92% and 90%, respectively, of this total was directed to California oil operations.

Our 2019 anticipated capital expenditure budget is approximately $195 to $225 million, which represents an increase of approximately 42% over 2018 capital expenditures. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2019 capital development programs while producing positive Levered Free Cash Flow. Our 2019 capital program is focused on growing our oil production in California. We anticipate oil production will be at least 86% of total production in 2019, compared to 82% in 2018. This change in product mix also factors in the divestiture of our non-core East Texas gas properties in late 2018. Our 2019 capital program was front-end loaded resulting in more wells drilled in the first half of the year than the amount we expect to drill in the second half. Consistent with our plan, we drilled 210 wells in the first six months of 2019, of which we expect 133 wells will generate growth in the last half of the year as they come online or realize the full effects of steam injection. During 2019, we expect to:

- employ up to four drilling rigs in California throughout the year; and
- drill approximately 370 to 400 gross development wells, all of which we expect will be in California for oil production.

The table below sets forth the expected allocation of our 2019 capital expenditure budget by area as compared to the allocation of our 2018 capital expenditures.

	Capital Expenditure by Area	
	2019 Budget	**2018 Actual**
	(in millions)	
California	$ 185-209	$ 126
Rockies	4-9	17
Corporate	6-7	5
Total	$ 195-225	$ 148

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility 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, natural gas and NGLs, 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 interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations.

2019 Guidance

The table below sets forth our 2019 Guidance for certain metrics.

	2019 Guidance	
	Low	High
Average daily production (MBoe/d)	28	31
% Oil	~86%	
Operating expenses ($/Boe)	$18.00	$19.50
Taxes, other than income taxes ($/Boe)	$4.25	$4.75
Adjusted General & Administrative Expenses ($/Boe)	$4.25	$4.75
Capital Expenditures (millions)	$195	$225

Business Environment, Market Conditions and Seasonality

The oil and gas industry is heavily influenced by commodity prices. Average oil prices were higher for the three months ended June 30, 2019 compared to the three months ended March 31, 2019 and lower than the three months ended June 30, 2018, and they fluctuated during each period. For instance, Brent crude oil contract prices ranged from $74.57 per Bbl to $59.97 per Bbl during the second quarter of 2019. In California, the daily price we paid for fuel gas purchases (generally based on the Kern Delivered Index) was as low as $0.99 per MMBtu and as high as $2.85 per MMBtu during the second quarter of 2019. Our revenue, costs, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production and the prices we pay for our natural gas purchases which will continue to be affected by a variety of factors, as discussed in Risk Factors in our Annual Report.

The following table presents the average Brent, WTI, and Kern, Delivered prices for the three months ended June 30, 2019, March 31, 2019 and June 30, 2018 and for the six months ended June 30, 2019 and June 30, 2018:

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	June 30, 2018
Brent oil ($/Bbl)	$ 68.47	$ 63.83	$ 74.97	$ 66.17	$ 71.16
WTI oil ($/Bbl)	$ 59.86	$ 54.87	$ 67.85	$ 57.38	$ 65.42
Kern, Delivered natural gas ($/MMBtu)	$ 2.07	$ 5.03	$ 2.23	$ 3.54	$ 2.44

California oil prices are Brent-influenced as California refiners import approximately 70% of the state’s demand by waterborne supply, primarily from the Middle East and South America. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, will allow us to continue to realize strong cash margins in California.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for Utah oil's unique characteristics and the remoteness of the assets makes access to other markets logistically challenging.

Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products for which they are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our steamfloods and power generation, than we produce and sell. Consequently, higher gas prices have a negative impact on our operating costs. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Additionally, we strive to minimize the variability of our fuel gas costs for our steam operations by hedging a portion of such gas purchases and have recently increased the amount of gas purchases we hedge. Also, the negative impact of higher gas prices is partially offset by higher gas sales for the gas we produce. We are currently negotiating terms of a new power purchase agreement for our 18 MW cogeneration facility for which the current agreement expires in October 2019.

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by three of our cogeneration facilities under long-term contracts. The most significant input and cost of the cogeneration facilities is natural gas. We receive significantly more revenue from these cogeneration facilities in the summer months, June through September, due to negotiated capacity payments we receive.

Seasonal weather conditions can impact a portion of our drilling and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires and rain.

Summary By Area

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated.

	California (San Joaquin and Ventura basins)			Rockies (Uinta and Piceance basins)		
	Three Months Ended			Three Months Ended		
($ in thousands, except prices)	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	March 31, 2019	June 30, 2018
Oil, natural gas and natural gas liquids sales	$ 120,917	$ 111,896	$ 117,288	$ 15,991	$ 19,206	$ 20,097
Operating income[(a)]	$ 47,809	$ 37,357	$ 60,014	$ 954	$ 4,779	$ 4,858
Depreciation, depletion, and amortization (DD&A)	$ 20,460	$ 21,342	$ 18,001	$ 3,194	$ 3,244	$ 3,140
Average daily production (MBoe/d)	20.8	21.0	18.8	6.6	6.8	7.7
Production (oil % of total)	100%	100%	100%	41%	46%	30%
Realized sales prices:						
Oil (per Bbl)	$ 63.91	$ 59.16	$ 68.72	$ 44.92	$ 41.38	$ 61.64
NGLs (per Bbl)	$ —	$ —	$ —	$ 16.86	$ 24.42	$ 24.38
Gas (per Mcf)	$ —	$ —	$ —	$ 2.16	$ 3.77	$ 2.12
Capital expenditures	$ 52,374	$ 42,509	$ 34,537	$ 1,443	$ 5,313	$ 3,735

(a) Operating income comprises oil, natural gas and NGL sales, offset by operating expenses, general and administrative expenses, DD&A, and taxes, other than income taxes.

Production, Prices and Costs

The following table sets forth information regarding average daily production, total production, average prices and average costs for each of the periods indicated.

	Three Months Ended		
	June 30, 2019	March 31, 2019	June 30, 2018
Average daily production:[(1)(5)]			
Oil (MBbl/d)	23.5	24.1	21.1
Natural Gas (MMcf/d)	20.8	19.5	28.0
NGL (MBbl/d)	0.4	0.4	0.7
Total (MBoe/d)[(2)]	27.4	27.8	26.5
Total Production:[(5)]			
Oil (MBbl)	2,142	2,170	1,920
Natural gas (MMcf)	1,894	1,752	2,551
NGLs (MBbl)	39	38	62
Total (MBoe)[(2)]	2,497	2,501	2,408
Weighted-average realized sales prices:			
Oil without hedges ($/Bbl)	$ 61.69	$ 56.88	$ 67.93
Oil with hedges ($/Bbl)	$ 61.82	$ 62.03	$ 53.22
Natural gas ($/Mcf)	$ 2.16	$ 3.83	$ 2.12
NGL ($/Bbl)	$ 16.86	$ 24.35	$ 24.38
Average Benchmark prices:			
Oil (Bbl) – Brent	$ 68.47	$ 63.83	$ 74.97
Oil (Bbl) – WTI	$ 59.86	$ 54.87	$ 67.85
Gas (MMBtu) – Kern, Delivered[(6)]	$ 2.07	$ 5.03	$ 2.23
Average costs per Boe:[(3)]			
Lease operating expenses	$ 19.18	$ 23.16	$ 17.24
Electricity generation expenses	1.27	3.10	1.30
Electricity sales[(3)]	(2.15)	(3.89)	(2.48)
Transportation expenses	0.68	0.87	0.97
Transportation sales[(3)]	(0.04)	(0.05)	(0.09)
Marketing expenses	0.17	0.34	0.17
Marketing revenues[(3)]	(0.17)	(0.33)	(0.22)
Derivatives settlements (received) paid for gas purchases[(3)]	1.44	(1.49)	—
Total operating expenses	$ 20.38	$ 21.71	$ 16.89
General and administrative expenses[(4)]	$ 6.47	$ 5.73	$ 5.18
Depreciation, depletion and amortization	$ 9.47	$ 9.83	$ 9.08
Taxes, other than income taxes	$ 4.54	$ 3.23	$ 3.62

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the three months ended June 30, 2019, the average prices of Brent oil and Henry Hub natural gas were $68.47 per Bbl and $2.57 per MMBtu respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

(3) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing revenues and expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(4) Includes restructuring and other non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.55 per Boe, $1.10 per Boe and $1.24 per Boe for the three months ended June 30, 2019, March 31, 2019 and June 30, 2018, respectively.

(5) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

(6) Kern Delivered Index is the relevant index used for gas purchases in California.

The following table sets forth average daily production by operating area for the periods indicated:

	Three Months Ended		
	June 30, 2019	March 31, 2019	June 30, 2018
Average daily production (MBoe/d):[1]			
California	20.8	21.0	18.8
Rockies	6.6	6.8	6.9
East Texas[2]	—	—	0.8
Total average daily production	27.4	27.8	26.5

(1) Production represents volumes sold during the period.

(2) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

Average daily production, including sales of inventory, was lower for the three months ended June 30, 2019 due to inventory sales in the three months ended March 31, 2019, as actual production was flat quarter over quarter.

Average daily production volumes increased for the three months ended June 30, 2019 as compared to the three months ended June 30, 2018 due to production response from development capital spending throughout 2018 and early 2019, offset by natural decline and the sale of our East Texas properties in November 2018. Our three months ended June 30, 2019 California production increased 11% compared to the three months ended June 30, 2018, as the substantial majority of our development capital was deployed throughout our California operations showing the strong ability of our California thermal properties to perform as expected.

The following table sets forth information regarding total production, average daily production, average prices and average costs for each of the periods indicated.

	Six Months Ended	
	June 30, 2019	June 30, 2018
Average daily production:(1)(5)		
Oil (MBbl/d)	23.8	21.1
Natural Gas (MMcf/d)	20.1	27.8
NGL (MBbl/d)	0.4	0.6
Total (MBoe/d)(2)	27.6	26.3
Total Production:(5)		
Oil (MBbl)	4,313	3,818
Natural gas (MMcf)	3,646	5,032
NGLs (MBbl)	77	108
Total (MBoe)(2)	4,998	4,764
Weighted-average realized sales prices:		
Oil without hedges ($/Bbl)	$ 59.27	$ 65.06
Oil with hedges ($/Bbl)	$ 61.92	$ 52.98
Natural gas ($/Mcf)	$ 2.96	$ 2.38
NGL ($/Bbl)	$ 20.59	$ 24.88
Average Benchmark prices:		
Oil (Bbl) – Brent	$ 66.17	$ 71.16
Oil (Bbl) – WTI	$ 57.38	$ 65.42
Gas (MMBtu) – Kern, Delivered(6)	$ 3.54	$ 2.44
Average costs per Boe:(3)		
Lease operating expenses	$ 21.17	$ 18.01
Electricity generation expenses	2.19	1.62
Electricity sales(3)	(3.02)	(2.40)
Transportation expenses	0.77	1.12
Transportation sales(3)	(0.04)	(0.05)
Marketing expenses	0.25	0.21
Marketing revenues(3)	(0.25)	(0.27)
Derivatives settlements (received) paid for gas purchases(3)	(0.03)	—
Total operating expenses	$ 21.04	$ 18.24
General and administrative expenses(4)	$ 6.10	$ 5.14
Depreciation, depletion and amortization	$ 9.65	$ 8.46
Taxes, other than income taxes	$ 3.89	$ 3.56

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the six months ended June 30, 2019, the average prices of Brent oil and Henry Hub natural gas were $66.17 per Bbl and $2.74 per MMBtu, respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

(3) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which are used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also includes the effect of derivative settlements (received or paid) for gas purchases.

(4) Includes restructuring and other non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.33 per Boe and $1.28 per Boe for the six months ended June 30, 2019 and June 30, 2018, respectively.

(5) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

(6) Kern Delivered Index is the relevant index used for gas purchases in California.

The following table sets forth average daily production by operating area for the periods indicated:

	Six Months Ended	
	June 30, 2019	June 30, 2018
Average daily production (MBoe/d):[1]		
California	20.9	18.8
Rockies	6.7	6.7
East Texas[2]	—	0.8
Total average daily production	27.6	26.3

(1) Production represents volumes sold during the period.

(2) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

Average daily production volumes increased for the six months ended June 30, 2019 compared to the six months ended June 30, 2018 due to production response from development capital spending throughout 2018 and 2019, offset by natural decline and the sale of our East Texas properties in November 2018. For the six months ended June 30, 2019 California production increased 11% compared to the six months ended June 30, 2018, as the substantial majority of our development capital was deployed throughout our California operations showing the strong ability of our California thermal properties to perform as expected.

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Results of Operations

Three Months Ended June 30, 2019 compared to Three Months Ended March 31, 2019.

	Three Months Ended			
	June 30, 2019	March 31, 2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 136,908	$ 131,102	$ 5,806	4 %
Electricity sales	5,364	9,729	(4,365)	(45)%
Gain (losses) on oil derivatives	27,276	(65,239)	92,515	n/a
Marketing and other revenues	518	947	(429)	(45)%
Total revenues and other	170,066	76,539	93,527	122 %
Expenses and other:				
Lease operating expenses	47,879	57,928	(10,049)	(17)%
Electricity generation expenses	3,164	7,760	(4,596)	(59)%
Transportation expenses	1,694	2,173	(479)	(22)%
Marketing expenses	421	851	(430)	(51)%
General and administrative expenses	16,158	14,340	1,818	13 %
Depreciation, depletion and amortization	23,654	24,585	(931)	(4)%
Taxes, other than income taxes	11,348	8,086	3,262	40 %
(Gains) losses on natural gas derivatives	9,449	(2,115)	11,564	n/a
Other operating expenses	3,119	1,245	1,874	151 %
Total expenses and other	116,886	114,853	2,033	2 %
Other income (expenses):				
Interest expense	(8,961)	(8,805)	(156)	2 %
Other, net	—	154	(154)	(100)%
Reorganization items, net	(26)	(231)	205	(89)%
Income (loss) before income taxes	44,193	(47,196)	91,389	n/a
Income tax expense (benefit)	12,221	(13,098)	25,319	n/a
Net income (loss)	$ 31,972	$ (34,098)	$ 66,070	n/a

Revenues and Other

Oil, natural gas and NGL sales increased $6 million, or 4%, to approximately $137 million for the three months ended June 30, 2019 compared to the three months ended March 31, 2019. This increase reflected higher oil prices that were partially offset by lower gas prices and oil volumes including the impact of selling more Utah oil inventory in the first quarter.

Electricity sales represent sales to utilities, and decreased $4 million, or 45%, to approximately $5 million for the three months ended June 30, 2019 compared to the three months ended March 31, 2019. The decrease reflected lower unit sales prices and volumes due to increased facility downtime for scheduled maintenance during the second quarter of 2019 and lower seasonal prices compared to the first quarter as expected.

Gains on oil derivatives were approximately $27 million for the three months ended June 30, 2019 compared to losses of approximately $65 million for the three months ended March 31, 2019. Gains for the second quarter of 2019 mostly resulted from the mark-to-market effect caused by decreasing oil prices relative to the fixed prices of our derivative contracts.

Marketing and other revenues decreased 45% to approximately $0.5 million for the three months ended June 30, 2019, compared to the three months ended March 31, 2019 mostly due to lower average gas prices. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

Expenses and Other

We report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which are used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery.

Operating expenses, as defined above in "How We Plan and Evaluate Operations", decreased to $20.38 per Boe for the three months ended June 30, 2019 from $21.71 per Boe for the three months ended March 31, 2019. This decrease was largely driven by fuel costs that were lower by $6.86 per Boe partially offset by settled gas hedge losses which increased by $2.93 per Boe.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased by approximately $10 million, or 17%, to approximately $48 million for the three months ended June 30, 2019, compared to the three months ended March 31, 2019.

Lease operating expenses were $19.18 per Boe for the three months ended June 30, 2019 compared to $23.16 per Boe for the three months ended March 31, 2019. Fuel prices related to our California steam operations recovered from unseasonably high prices during the three months ended March 31, 2019. The average fuel cost for the second quarter of 2019 decreased 58% to $2.03/MMBtu compared to $4.87/MMBtu for the first quarter of 2019. The decrease in fuel costs was partially offset by increases in facility, well, and lease maintenance costs during the second quarter of 2019. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased approximately $5 million or 59% to $3 million for the three months ended June 30, 2019 compared to the three months ended March 31, 2019. The decrease reflected lower seasonal fuel costs and volumes due to increased downtime for scheduled maintenance during the second quarter of 2019. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $9 million for the three months ended June 30, 2019, consisted of losses on settled derivative contracts and mark-to-market valuation losses. The $2 million gain on natural gas derivatives for the three months ended March 31, 2019 resulted from gains on settled contracts that were partially offset by mark-to-market valuation losses. Additionally, we increased our gas purchase hedge positions during the second quarter of 2019 to stabilize our fuel costs.

Transportation expenses were flat for the three months ended June 30, 2019 and March 31, 2019.

Marketing expenses were flat for the three months ended June 30, 2019 and March 31, 2019. Marketing expenses in these periods represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by approximately $2 million, or 13%, to approximately $16 million for the three months ended June 30, 2019 compared to the three months ended March 31, 2019. The second quarter was affected by higher non-cash stock compensation associated with the annual grant of stock awards in March. For the three months ended June 30, 2019 and March 31, 2019, general and administrative expenses included restructuring and other non-recurring costs of approximately $1.5 million and $1.3 million, respectively, and non-cash stock compensation costs of approximately $2.4 million and $1.4 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were $12.3 million or $4.92/Boe for the second quarter 2019 compared to $11.6 million or $4.63/Boe for the first quarter 2019. This increase was primarily due to organizational growth and system enhancements. Adjusted general and administrative expenses is a non-GAAP financial measure defined as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense. Please see “—Non-GAAP Financial Measure” for a reconciliation to the GAAP financial measure of general and administrative expenses.

DD&A was approximately $24 million for the three months ended June 30, 2019, and was comparable to the three months ended March 31, 2019.

Taxes, Other Than Income Taxes

	Three Months Ended			
	June 30, 2019	March 31, 2019	$ Change	% Change
	(in thousands)			
Severance taxes	$ 1,873	$ 703	$ 1,170	166%
Ad valorem and property taxes	3,612	3,145	467	15%
Greenhouse gas allowances	5,863	4,238	1,625	38%
Total taxes other than income taxes	$ 11,348	$ 8,086	$ 3,262	40%
Taxes, other than income taxes ($/Boe)	$ 4.54	$ 3.23		

Taxes, other than income taxes increased in the three months ended June 30, 2019 by $3 million or 40%, compared to the three months ended March 31, 2019 due to higher greenhouse gas allowance market prices, severance taxes, and ad valorem and property taxes. Greenhouse gas costs increased as a result of higher market prices which increased the average unit cost of emissions incurred. Ad valorem and property taxes increased in the second quarter of 2019 due to higher supplemental assessments than the first quarter 2019. Severance tax refunds received during the first quarter 2019, decreased the related expense compared to the second quarter of 2019.

Other operating expenses

Other operating expenses were $3 million in the quarter ended June 30, 2019 and mainly consisted of increased excess abandonment costs during the period compared to the quarter ended March 31, 2019.

Reorganization items, net

Reorganization items, net were not significant for the three months ended June 30, 2019 and March 31, 2019.

Income Tax Expense (Benefit)

Our effective tax rate remained flat at 27.7% for the three months ended June 30, 2019 and 27.8% for the three months ended March 31, 2019.

Three Months Ended June 30, 2019 compared to Three Months Ended June 30, 2018.

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 136,908	$ 137,385	$ (477)	— %
Electricity sales	5,364	5,971	(607)	(10)%
Gain (losses) on oil derivatives	27,276	(78,143)	105,419	n/a
Marketing and other revenues	518	769	(251)	(33)%
Total revenues and other	170,066	65,982	104,084	158 %
Expenses and other:				
Lease operating expenses	47,879	41,517	6,362	15 %
Electricity generation expenses	3,164	3,135	29	1 %
Transportation expenses	1,694	2,343	(649)	(28)%
Marketing expenses	421	407	14	3 %
General and administrative expenses	16,158	12,482	3,676	29 %
Depreciation, depletion and amortization	23,654	21,859	1,795	8 %
Taxes, other than income taxes	11,348	8,715	2,633	30 %
(Gains) losses on natural gas derivatives	9,449	—	9,449	n/a
Other operating expenses	3,119	123	2,996	2,436 %
Total expenses and other	116,886	90,581	26,305	29 %
Other income (expenses):				
Interest expense	(8,961)	(9,155)	194	(2)%
Other, net	—	(239)	239	(100)%
Reorganization items, net	(26)	456	(482)	(106)%
Income (loss) before income taxes	44,193	(33,537)	77,730	n/a
Income tax expense (benefit)	12,221	(5,476)	17,697	n/a
Net income (loss)	31,972	(28,061)	60,033	n/a
Series A preferred stock dividends	—	(5,650)	5,650	(100)%
Net income (loss) available to common stockholders	$ 31,972	$ (33,711)	$ 65,683	n/a

Revenues and Other

Oil, natural gas and NGL sales were essentially flat at approximately $137 million for the three months ended June 30, 2019 and the three months ended June 30, 2018. Higher oil volumes were offset by lower oil prices and gas volumes between the periods.

Electricity sales, representing sales to utilities, decreased by approximately $1 million, or 10%, to approximately $5 million for the three months ended June 30, 2019 compared to the three months ended June 30, 2018. The decrease was primarily due to lower sales caused by increased downtime for scheduled maintenance, in the three months ended June 30, 2019, compared to the three months ended June 30, 2018.

Gains on oil derivatives were $27 million, net of realized gains of $0.3 million, for the three months ended June 30, 2019 and $78 million, net of realized losses of $28 million, for the three months ended June 30, 2018. Gains for the second quarter of 2019 and 2018 mostly resulted from the mark-to-market effect caused by decreasing oil prices relative to the fixed prices of our derivative contracts.

Marketing and other revenues decreased approximately 33% to $0.5 million for the three months ended June 30, 2019, compared to the three months ended June 30, 2018 due to lower average sales prices and lower volumes handled. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

Expenses and Other

Operating expenses, as defined above in "How We Plan and Evaluate Operations", increased to $20.38 per Boe for the three months ended June 30, 2019 from $16.89 per Boe for the three months ended June 30, 2018. The second quarter of 2019 included a loss of $1.44 per Boe on settled gas hedges and $1.93 per Boe in higher lease operating expenses.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased approximately $6 million, or 15%, to approximately $48 million for the three months ended June 30, 2019, compared to the three months ended June 30, 2018.

Lease operating expenses were $19.18 per Boe for the three months ended June 30, 2019 compared to $17.25 per Boe for the three months ended June 30, 2018. The increased costs related to facility and well servicing maintenance, recompletion activity and gas purchases were partially offset by lower gas costs, compared to the three months ended June 30, 2018. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses were $3 million for each of the three months ended June 30, 2019 and 2018. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $9 million for the three months ended June 30, 2019 consisted of realized losses on settled derivative contracts and mark-to-market valuation losses. We did not have any natural gas derivatives during the three months ended June 30, 2018.

Transportation expenses decreased by less than $1 million to approximately $2 million for the three months ended June 30, 2019, compared to the three months ended June 30, 2018, mainly due to lower volumes shipped from our Rockies assets and the impact from selling our East Texas asset during the fourth quarter of 2018.

Marketing expenses were comparable for the three months ended June 30, 2019 and June 30, 2018. Marketing expenses in these periods represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by approximately $4 million, or 29%, to approximately $16 million for the three months ended June 30, 2019 compared to the three months ended June 30, 2018. For the three months ended June 30, 2019 and June 30, 2018, general and administrative expenses included restructuring and other non-recurring costs of approximately $1.5 million and $1.7 million, respectively, and non-cash stock compensation costs of approximately $2.4 million and $1.3 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were $12.3 million or $4.92/Boe for the second quarter 2019 compared to $9.5 million or $3.95/Boe for the second quarter 2018. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth and public company status.

DD&A increased by approximately $2 million, or 8%, to approximately $24 million, for the three months ended June 30, 2019 compared to the three months ended June 30, 2018, primarily due to the increased production and higher depreciation and depletion rates for 2019.

Taxes, Other Than Income Taxes

	Three Months Ended June 30,			
	2019	**2018**	**$ Change**	**% Change**
	(in thousands)			
Severance taxes	$ 1,873	$ 2,997	$ (1,124)	(38)%
Ad valorem and property taxes	3,612	3,141	471	15 %
Greenhouse gas allowances	5,863	2,577	3,286	128 %
Total taxes other than income taxes	$ 11,348	$ 8,715	$ 2,633	30 %
Taxes, other than income taxes ($/Boe)	$ 4.54	$ 3.62		

Taxes, other than income taxes increased for the three months ended June 30, 2019 by $2.6 million or 30%, compared to the three months ended June 30, 2018 due to higher greenhouse gas cost allowances and ad valorem and property taxes, partially offset by lower severance taxes than in the second quarter 2018. Greenhouse gas costs increased as a result of fewer free allowances from the state of California and higher spot prices for those allowances purchased, both of which increased the average unit cost of emissions incurred. The lower severance taxes in the second quarter of 2019 were the result of increased exemptions.

Other operating expenses

Other operating expenses were $3 million in the quarter ended June 30, 2019 and mainly consisted of increased excess abandonment costs during the period compared to the quarter ended June 30, 2018.

Interest Expense

Interest expense decreased in the three months ended June 30, 2019 by approximately $0.2 million or 2%, compared to the three months ended June 30, 2018 due to lower borrowings throughout the second quarter of 2019 compared to 2018.

Reorganization items, net

Reorganization items, net was insignificant for the three months ended June 30, 2019, compared to $0.5 million of income for the three months ended June 30, 2018. The gain was primarily due to the resolution of certain pre-emergence liabilities, partially offset by legal and other professional fees.

Income Tax Expense (Benefit)

Our effective tax rate was 27.7% for the three months ended June 30, 2019 and 16.3% for the three months ended June 30, 2018. The increase in the effective tax rate was primarily due to the release of our valuation allowance on deferred tax assets in 2018.

Six Months Ended June 30, 2019 compared to Six Months Ended June 30, 2018.

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 268,010	$ 263,010	$ 5,000	2 %
Electricity sales	15,093	11,423	3,670	32 %
Gain (losses) on oil derivatives	(37,963)	(112,787)	74,824	(66)%
Marketing and other revenues	1,465	1,619	(154)	(10)%
Total revenues and other	246,605	163,265	83,340	51 %
Expenses and other:				
Lease operating expenses	105,807	85,819	19,988	23 %
Electricity generation expenses	10,924	7,725	3,199	41 %
Transportation expenses	3,867	5,321	(1,454)	(27)%
Marketing expenses	1,272	987	285	29 %
General and administrative expenses	30,498	24,466	6,032	25 %
Depreciation, depletion and amortization	48,240	40,288	7,952	20 %
Taxes, other than income taxes	19,434	16,972	2,462	15 %
(Gains) losses on natural gas derivatives	7,334	—	7,334	100 %
Other operating expenses	4,364	123	4,241	3,448 %
Total expenses and other	231,740	181,701	50,039	28 %
Other income (expenses):				
Interest expense	(17,766)	(16,951)	(815)	5 %
Other, net	155	(212)	367	n/a
Reorganization items, net	(257)	9,411	(9,668)	(103)%
Income (loss) before income taxes	(3,003)	(26,188)	23,185	(89)%
Income tax expense (benefit)	(877)	(4,537)	3,660	(81)%
Net income (loss)	(2,126)	(21,651)	19,525	(90)%
Series A preferred stock dividends	—	(11,301)	11,301	(100)%
Net income (loss) available to common stockholders	$ (2,126)	$ (32,952)	$ 30,826	(94)%

Revenues and Other

Oil, natural gas and NGL sales increased $5 million, or 2% to approximately $268 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018 due to a 13% increase in oil volumes, including the impact from selling more Utah oil inventory in 2019, partially offset by a 9% decrease in oil prices and a 28% decrease in gas volumes.

Electricity sales represent sales to utilities and increased by approximately $4 million, or 32%, to approximately $15 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018. The increase was primarily due to higher sales prices, due to the link between sales price and higher natural gas pricing, in the six months ended June 30, 2019, than the six months ended June 30, 2018.

Losses on oil derivatives were $38 million, net of realized gains of $11 million, for the six months ended June 30, 2019 compared to a loss of $113 million, net of realized losses of $46 million, for the six months ended June 30, 2018. Each total loss was due to improved commodity prices relative to the fixed prices of our derivative contracts.

Marketing and other revenues decreased 10% to approximately $1 million for the six months ended June 30, 2019, compared to the six months ended June 30, 2018 mostly due to decreased volumes handled. Marketing revenues in these periods represented sales of natural gas purchased from third-parties.

Expenses and Other

Operating expenses, as defined above in "How We Plan and Evaluate Operations", increased to $21.04 per Boe for the six months ended June 30, 2019 from $18.24 per Boe for the six months ended June 30, 2018, which included an increase in fuel costs of $2.42 per Boe. The impact from our settled gas hedges was not significant for the six months ended June 30, 2019 and 2018.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $20 million, or 23%, to approximately $106 million for the six months ended June 30, 2019, compared to the six months ended June 30, 2018.

Lease operating expenses were $21.17 per Boe for the six months ended June 30, 2019 compared to $18.01 per Boe for the six months ended June 30, 2018. The increase was primarily due to higher fuel costs that increased fuel expense approximately $14 million or $2.42 per Boe for the six months ended June 30, 2019 compared to the six months ended June 30, 2018. The fuel gas cost for the 2019 period was $3.40/MMBtu compared to $2.53/MMBtu in 2018.

Electricity generation expenses increased approximately $3 million or 41% to $11 million for the six months ended June 30, 2019 and the six months ended June 30, 2018, mostly due to higher natural gas costs during 2019. These fuel costs exclude the the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $7 million for the six months ended June 30, 2019 primarily represented mark-to-market valuation losses. We did not have any natural gas derivatives during the six months ended June 30, 2018.

Transportation expenses decreased approximately $1 million to approximately $4 million for the six months ended June 30, 2019, compared to the six months ended June 30, 2018, mainly due to lower volumes shipped from our Rockies assets and impact from selling our East Texas asset during the fourth quarter of 2018.

Marketing expenses increased $0.3 million or 29% to $1 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018, primarily due to higher natural gas costs. Marketing expenses in these periods represented the cost of natural gas purchased from third-parties.

General and administrative expenses increased by approximately $6 million, or 25%, to approximately $30 million for the six months ended June 30, 2019 compared to the six months ended June 30, 2018. For the six months ended June 30, 2019 and June 30, 2018, general and administrative expenses included restructuring and other non-recurring costs of approximately $3 million and $4 million, respectively, and non-cash stock compensation costs of approximately $4 million and $2 million, respectively.

Adjusted general and administrative expenses, which exclude restructuring and other non-recurring costs and non-cash stock compensation costs, were $24 million or $4.77/Boe for the first six months in 2019 compared to $18 million or $3.87/Boe for the first six months in 2018. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth and public company status.

DD&A increased by approximately $8 million, or 20%, to approximately $48 million, for the six months ended June 30, 2019 compared to the six months ended June 30, 2018, primarily due to the increased production and higher depreciation and depletion rates for 2019.

Taxes, Other Than Income Taxes

	Six Months Ended June 30,			
	2019	**2018**	**$ Change**	**% Change**
	(in thousands)			
Severance taxes	$ 2,577	$ 5,761	$ (3,184)	(55)%
Ad valorem and property taxes	6,757	6,558	199	3 %
Greenhouse gas allowances	10,100	4,653	5,447	117 %
Total taxes other than income taxes	$ 19,434	$ 16,972	$ 2,462	15 %
Taxes, other than income taxes ($/Boe)	$ 3.89	$ 3.56		

Taxes, other than income taxes increased in the six months ended June 30, 2019 by $2 million or 15%, compared to the six months ended June 30, 2018 due to higher greenhouse gas allowance costs, partially offset by lower severance taxes than in the six months ended June 30, 2018. Greenhouse gas allowance costs increased as a result of fewer free allowances from the state of California and higher spot prices for those allowances purchased, both of which increased the average unit cost of emissions incurred. The lower severance taxes in the six months ended 2019 were the result of increased exemptions.

Other operating expenses

Other operating expenses were $4 million in the six months ended June 30, 2019 and mainly consisted of increased excess abandonment costs during the period compared to the six months ended June 30, 2018.

Interest Expense

Interest expense increased in the six months ended June 30, 2019 by approximately $1 million or 5%, compared to the six months ended June 30, 2018, due to six months of interest on the 2026 Notes in the six months ended June 30, 2019 compared to four and a half months during the six months ended June 30, 2018.

Reorganization items, net

Reorganization items, net consisted of essentially no expense for the six months ended June 30, 2019, compared to $9 million of income primarily from the return of undistributed funds reserved for settlement of claims of general unsecured creditors for the six months ended June 30, 2018.

Income Tax Expense (Benefit)

Our effective tax rate was 29.2% for the six months ended June 30, 2019 and 17.3% for the six months ended June 30, 2018. The increase in the effective tax rate was primarily due to the release of our valuation allowance on deferred tax assets in 2018.

Non-GAAP Financial Measures

Adjusted EBITDA, Levered Free Cash Flow and Adjusted Net Income (Loss)

Adjusted EBITDA and Adjusted Net Income (Loss) are not measures of net income (loss) and Levered Free Cash Flow is not a measure of cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. Levered Free Cash Flow is used by management as a primary metric to plan capital allocation for maintenance and internal growth opportunities, as well as hedging needs. It also serves as a measure for assessing our financial performance and our ability to generate excess cash from operations to service debt and pay dividends.

Adjusted Net Income (Loss) excludes the impact of unusual, out-of-period and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate.

While Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Our computations of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

Adjusted General and Administrative Expenses is a supplemental non-GAAP financial measure that is used by management. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period.

We exclude the items listed above from general and administrative expenses in arriving at Adjusted General and Administrative Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Adjusted General and Administrative Expenses should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Our computations of Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures of other companies.

The following tables present reconciliations of the non-GAAP financial measures Adjusted EBITDA and Levered Free Cash Flow to the GAAP financial measures of net income (loss) and net cash provided or used by operating activities, as applicable, for each of the periods indicated.

	Three Months Ended			Six Months Ended	
	June 30, 2019	**March 31, 2019**	**June 30, 2018**	**June 30, 2019**	**June 30, 2018**
			(in thousands)		
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ 31,972	$ (34,098)	$ (28,061)	$ (2,126)	$ (21,651)
Add (Subtract):					
Interest expense	8,961	8,805	9,155	17,766	16,951
Income tax expense (benefit)	12,221	(13,098)	(5,476)	(877)	(4,537)
Depreciation, depletion and amortization	23,654	24,585	21,859	48,240	40,288
Derivative losses (gains)	(17,827)	63,124	78,143	45,297	112,787
Net cash received (paid) for scheduled derivative settlements	(3,326)	14,904	(28,261)	11,578	(46,110)
Other operating expenses	3,119	1,245	123	4,364	123
Stock compensation expense	2,443	1,475	1,278	3,918	2,320
Restructuring and other non-recurring costs	1,513	1,329	1,714	2,842	3,761
Reorganization items, net	26	231	(456)	257	(9,411)
Adjusted EBITDA	$ 62,756	$ 68,502	$ 50,018	$ 131,258	$ 94,521

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	June 30, 2018
			(in thousands)		
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided (used) by operating activities:					
Net cash provided (used) by operating activities(1)	$ 71,362	$ 19,111	$ (77,394)	$ 90,473	$ (49,548)
Add (Subtract):					
Cash interest payments	1,272	14,000	644	15,272	3,298
Cash reorganization item (receipts) payments	—	—	1,047	—	1,352
Restructuring and other non-recurring costs	1,513	1,329	1,714	2,842	3,761
Derivative early termination payment	—	—	126,949	—	126,949
Other changes in operating assets and liabilities	(11,391)	34,063	(2,942)	22,672	8,709
Adjusted EBITDA	$ 62,756	$ 68,502	$ 50,018	$ 131,258	$ 94,521
Subtract:					
Capital expenditures - accrual basis	(56,645)	(49,099)	(38,531)	(105,744)	(54,928)
Interest expense	(8,961)	(8,805)	(9,155)	(17,766)	(16,951)
Cash dividends declared	(9,710)	(10,072)	(5,651)	(19,782)	(11,301)
Levered Free Cash Flow(2)	$ (12,560)	$ 526	$ (3,319)	$ (12,034)	$ 11,341

(1) The three months ended March 31, 2019 included $37 million of annual or semi-annual payments that occur in the first quarter each year such as semi-annual interest and certain annual royalty payments and other accrued liabilities.

(2) Levered Free Cash Flow, as defined by the Company, includes cash paid for scheduled derivative settlements of $3 million in the three months ended June 30, 2019, cash received for scheduled derivative settlements of $15 million in the three months ended March 31, 2019 and cash paid for scheduled derivatives settlements of $28 million for the three months ended June 30, 2018. Levered Free Cash Flow includes cash received for scheduled derivative settlements of $12 million in the six months ended June 30, 2019 and cash paid for scheduled derivative settlements of $46 million for the six months ended June 30, 2018.

The following table presents a reconciliation of the non-GAAP financial measure Adjusted Net Income (Loss) to the GAAP financial measure of Net income (loss).

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	June 30, 2018
			(in thousands)		
Adjusted Net Income (Loss) reconciliation to net income (loss)					
Net income (loss)	$ 31,972	$ (34,098)	$ (28,061)	$ (2,126)	$ (21,651)
Add (Subtract):					
(Gains) losses on oil and natural gas derivatives	(17,827)	63,124	78,143	45,297	112,787
Net cash received (paid) for scheduled derivative settlements	(3,326)	14,904	(28,261)	11,578	(46,110)
Other operating expenses	3,119	1,245	123	4,364	123
Restructuring and other non-recurring costs	1,513	1,329	1,714	2,842	3,761
Reorganization items, net	26	231	(456)	257	(9,411)
Total additions (subtractions), net	(16,495)	80,833	51,263	64,338	61,150
Income tax (expense) benefit of adjustments at effective tax rate	4,569	(22,471)	(8,371)	(18,787)	(10,594)
Adjusted Net Income (Loss)	$ 20,046	$ 24,264	$ 14,831	$ 43,425	$ 28,905

The following table presents a reconciliation of the non-GAAP financial measure Adjusted General and Administrative Expenses to the GAAP financial measure of general and administrative expenses for each of the periods indicated.

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	June 30, 2018
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
G&A expenses	$ 16,158	$ 14,340	$ 12,482	$ 30,498	$ 24,466
Subtract:					
Restructuring and other non-recurring costs	(1,513)	(1,329)	(1,714)	(2,842)	(3,761)
Non-cash stock compensation expense (G&A portion)	(2,368)	(1,424)	(1,260)	(3,792)	(2,279)
Adjusted G&A	$ 12,277	$ 11,587	$ 9,508	$ 23,864	$ 18,426
Adjusted general and administrative expenses ($/MBoe)	$ 4.92	$ 4.63	$ 3.95	$ 4.77	$ 3.87

Liquidity and Capital Resources

Currently, we expect our primary sources of liquidity and capital resources will be Levered Free Cash Flow, and as needed, borrowings under the RBL Facility. Depending upon market conditions and other factors, we have issued and may issue additional equity and debt securities; however, we expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations, organic growth, interest, dividends and, opportunistic repurchases of our common stock or debt. We believe our liquidity and capital resources will be sufficient to conduct our business and operations for the next 12 months.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and we are not obligated to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

For the three months ended June 30, 2019, we repurchased 1,000,000 shares at an average price of $10.90 per share for $11 million, which is reflected as treasury stock. For the six months ended June 30, 2019, we repurchased 3,200,162 shares at an average price of $11.02 per share for $35 million, which is reflected as treasury stock. The Company has repurchased a total of 3,648,823 shares under the stock repurchase program for $39 million as of June 30, 2019.

Cash Dividends

Our board of directors approved $0.12 per share quarterly cash dividends on our common stock for the first, second and third quarters of 2019. We paid the second quarter dividend in July 2019 and declared the third quarter dividend in July 2019, which is payable in October 2019. As of July 31, 2019, the Company has declared approximately $47 million, and paid $37 million, in dividends since the inception of its dividend program.

The RBL Facility

As of June 30, 2019 our borrowing base was $400 million and we had $386 million available for borrowing under the RBL Facility. At June 30, 2019, we were in compliance with the financial covenants under the RBL Facility. In April 2019, we completed a borrowing base redetermination under our RBL Facility that resulted in our borrowing base being set at $750 million and we elected to limit lender commitments to $400 million. Borrowing base redeterminations become effective on, or about, each May 1 and November 1, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations.

Corporate Organization

Berry Corp., as Berry LLC's parent company, has no independent assets or operations. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. Berry Corp. and Berry LLC currently do not have any other subsidiaries. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than under the RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

Hedging

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including through fixed-price derivative contracts. We hedge crude oil production to protect against oil price decreases and we also hedge gas purchases to protect against price increases For information regarding risks related to our hedging program, see “Item 1A. Risk Factors—Risks Related to Our Business and Industry” in our Annual Report.

As of June 30, 2019, we had the following crude oil production and gas purchases hedges, with no changes through July 31, 2019.

	Q3 2019	Q4 2019	FY 2020
Sold Oil Call Options (Brent):			
Hedged volume (MBbls)	92	92	—
Weighted average price ($/Bbl)	$ 81.00	$ 81.00	$ —
Purchased Oil Put Options (Brent):			
Hedged volume (MBbls)	460	460	—
Weighted-average price ($/Bbl)	$ 50.00	$ 50.00	$ —
Fixed Price Oil Swaps (Brent):			
Hedged volume (MBbls)	1,472	1,380	4,392
Weighted average price ($/Bbl)	$ 72.64	$ 72.21	$ 65.70
Fixed Price Oil Swaps (WTI):			
Hedged volume (MBbls)	92	92	121
Weighted average price ($/Bbl)	$ 61.75	$ 61.75	$ 61.75
Oil basis differential positions (Brent-WTI basis swaps):			
Hedged volume (MBbls)	46	46	—
Weighted average price ($/Bbl)	$ (1.29)	$ (1.29)	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	4,600,000	4,295,000	13,725,000
Weighted average price ($/MMBtu)	$ 2.91	$ 2.95	$ 2.98
Fixed Price Gas Purchase Swaps (SoCal Citygate):			
Hedged volume (MMBtu)	460,000	460,000	1,525,000
Weighted average price ($/MMBtu)	$ 3.80	$ 3.80	$ 3.80

The following table summarizes the historical results of our hedging activities.

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	June 30, 2019	June 30, 2018
Crude Oil (per Bbl):					
Realized sales price, before the effects of derivative settlements	$ 61.69	$ 56.88	$ 67.93	$ 59.27	$ 65.06
Effects of derivative settlements	$ 0.13	$ 5.15	$ (14.71)	$ 2.65	$ (12.08)
Natural Gas (per MMBtu):					
Purchase price, before the effects of derivative settlements	$ 2.03	$ 4.87	$ 2.36	$ 3.40	$ 2.53
Effects of derivative settlements	$ 0.53	$ (0.59)	$ —	$ (0.01)	$ —

We expect our operations to generate substantial cash flows at current commodity prices. We have protected a portion of our anticipated cash flows through 2020 as part of our crude oil hedging program. Our low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. The decrease in derivative settlements from first quarter 2019 to second quarter 2019 is the result of an increase in Brent prices compared to the respective hedge strike prices, narrowing the hedge impact.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(in thousands)	
Net cash:		
Provided by (used in) operating activities	$ 90,473	$ (49,548)
Used in investing activities	(107,379)	(42,347)
Provided by (used in) financing activities	(51,547)	46,467
Net decrease in cash, cash equivalents and restricted cash	$ (68,453)	$ (45,428)

Operating Activities

Cash provided by operating activities increased for the six months ended June 30, 2019 by approximately $140 million when compared to the six months ended June 30, 2018, primarily due to the early termination of certain hedge contracts during the second quarter of 2018, the increase in oil sales and electricity sales, the increase in derivative cash settlements received, offset by the increased operating costs mainly due to higher fuel costs and the semi-annual interest payments on our 2026 Senior Unsecured Notes paid for the first time in August 2018, and other working capital changes.

Investing Activities

The following provides a comparative summary of cash flows from investing activities:

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(in thousands)	
Capital expenditures:(1)		
Development of oil and natural gas properties	$ (95,538)	$ (37,609)
Purchase of other property and equipment	(9,190)	(7,760)
Acquisition of properties	(2,689)	—
Proceeds from sale of properties and equipment and other	38	3,022
Cash used in investing activities	$ (107,379)	$ (42,347)

(1) Based on actual cash payments rather than accruals.

Cash used in investing activities increased $65 million for the six months ended June 30, 2019, when compared to the same period in 2018, primarily due to an increase in capital spending in accordance with the 2019 capital budget.

Financing Activities

Cash used by financing activities was approximately $52 million for the six months ended June 30, 2019 and was primarily used to purchase treasury stock of $36 million and pay dividends on common stock of approximately $20 million, offset by the $5 million of borrowings under the RBL Facility for monthly working capital fluctuations. Cash provided by financing activities was approximately $46 million for the six months ended June 30, 2018 and was primarily provided by the issuance of the 2026 Senior Unsecured Notes in the aggregate principal amount of $400 million and additional borrowings under the RBL Facility of $97 million, offset by the repayments on the new credit facility of approximately $410 million, the purchase of treasury stock for $20 million, the payment of $11 million in dividends on our Series A Preferred Stock and the payment of $9 million of debt issuance costs.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2018 to June 30, 2019 are discussed below.

	June 30, 2019	December 31, 2018
	(in thousands)	
Cash and cash equivalents	$ 227	$ 68,680
Accounts receivable, net	$ 54,871	$ 57,379
Derivative instruments assets - current and long-term	$ 38,227	$ 91,885
Other current assets	$ 22,250	$ 14,367
Property, plant & equipment, net	$ 1,526,004	$ 1,442,708
Other non-current assets	$ 15,162	$ 17,244
Accounts payable and accrued liabilities	$ 127,110	$ 144,118
Derivative instruments liabilities - current and long-term	$ 7,615	$ —
Long-term debt	$ 397,315	$ 391,786
Asset retirement obligation	$ 102,291	$ 89,176
Other non-current liabilities	$ 25,148	$ 14,902
Equity	$ 952,316	$ 1,006,446

See "Liquidity and Capital Resources" for discussions about the changes in cash and cash equivalents.

The $3 million decrease in accounts receivable was driven mostly by lower hedge settlement receivables, partially offset by higher sales period-over-period.

The $46 million decrease in the derivative instruments assets and liabilities reflected the decrease in the mark-to-market values of our derivatives at the end of each period presented, as well as the change in positions held during the period. The decrease resulted from increased oil and natural gas prices relative to the fixed prices of our derivative contracts.

The $8 million increase in other current assets includes $5 million for materials inventory related to our capital development program and $3 million for prepaid software, insurance and other costs.

The $83 million increase in property, plant and equipment was largely the result of increased capital investments in oil and gas properties, as well as increased costs related to the change in timing of our asset retirement obligations noted below, partially offset by increased accumulated depreciation associated with such properties.

The $2 million decrease in other non-current assets was primarily due to amortization of debt issuance costs.

The decrease in accounts payable and accrued liabilities included $9 million for royalty payments, a $4 million decrease due to the timing of payments for trade and other payables and accruals, $4 million related to our incentive compensation program, and $3 million for lower accrued severance taxes. These decreases were partially offset by a $3 million increase in the current portion of the asset retirement obligation.

The nearly $6 million increase in long-term debt represented borrowing and repayment activity from our RBL Facility.

The increase in the long-term portion of the asset retirement obligation largely reflected an increase in the estimate of $18 million, $2 million in new wells, and accretion expense of $3 million. The change in estimate was a result of California's new idle well regulations effective in the second quarter. This accelerated the timing of abandonment of certain wells. These increases were partially offset by liabilities settled during the period of $8 million and an increase to the current portion of the asset retirement obligation of $3 million.

The increase in other noncurrent liabilities represented an additional greenhouse gas liability of $10 million for production during the six months ended June 30, 2019, which is due for payment more than one year from June 30, 2019.

The decrease in equity of $54 million was due to the purchase of treasury stock for $35 million and common stock dividends declared of $20 million. These decreases were offset by net loss of $2 million and stock-based incentive awards of $4 million.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at June 30, 2019 and December 31, 2018. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of June 30, 2019, we are not aware of material indemnity claims pending or threatened against us.

In April 2019, we sold our outstanding claims in the Pacific Gas & Electric bankruptcy at an immaterial loss.

Contractual Obligations

During the six months ended June 30, 2019, we entered into agreements to replace our Bakersfield, California office lease for approximately $11 million in aggregate over 8 years beginning August 2019. The annual costs under our current office lease, which ends in 2019, are similar to the costs under the new leases.

Recently Adopted Accounting and Disclosure Changes

See Note 1, Basis of Presentation, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this prospectus or in any accompanying prospectus supplement includes forward-looking statements involving risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, maintenance capital requirements, expected production and costs, reserves, hedging activities, capital expenditures, return of capital, improvement of recovery factors and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect us are discussed above in “Risk Factors” in this prospectus, in any applicable prospectus supplement and in the documents incorporated by reference, including our most recent Annual Report on Form 10-K.

Factors (but not necessarily all the factors) that could cause results to differ include among others:

- volatility of oil, natural gas and NGL prices;
- price and availability of natural gas;
- our ability to use derivative instruments to manage commodity price risk;
- our ability to obtain permits and otherwise to meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;

- impact of environmental, health and safety, and other governmental regulations, and of current, pending, or future legislation;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;
- changes in tax laws;
- effects of competition;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- ineffectiveness of internal controls;
- concerns about climate change and other air quality issues;
- catastrophic events;
- litigation;
- our ability to retain key members of our senior management and key technical employees; and
- information technology failures or cyber attacks.

Except as required by law, we undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

All forward-looking statements, expressed or implied, included in this prospectus 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three months ended June 30, 2019, there were no material changes in the information required to be provided under Item 305 of Regulation S-K included under the caption *Management's Discussion and Analysis of Financial Condition and Results of Operations (Incorporating Item 7A)- Quantitative and Qualitative Disclosures About Market Risk,* in the 2018 Annual Report, except as discussed below.

Price Risk

Our most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected to the extent unhedged. In addition, a non-cash write-down of our oil and gas properties may be required if commodity prices experience a significant decline.

We have hedged a large portion of our expected crude oil production and our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls and puts to hedge. We do not enter into derivative contracts for speculative trading purposes and we have not accounted for our derivatives as cash-flow or fair-value hedges. We continuously consider the level of our oil production and gas purchases that it is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, our overall risk profile, including leverage, size and scale, as well as any requirements for, or restrictions on, levels of hedging contained in any credit facility or other debt instrument applicable at the time. Currently, our hedging program mainly consists of swaps and puts.

We determine the fair value of our oil and natural gas derivatives using valuation techniques which utilize market quotes and pricing analysis. Inputs include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate data provided by third parties by understanding the valuation inputs used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. At June 30, 2019, the fair value of our hedge positions was a net asset of approximately $31 million. A 10% increase in the oil and natural gas index prices above the June 30, 2019 prices would result in a net asset of approximately $0.3 million, which represents a decrease in the fair value of our derivative position of approximately $30 million; conversely, a 10% decrease in the oil and natural gas index prices below the June 30, 2019 prices would result in a net asset of approximately $82 million, which represents an increase in the fair value of approximately $52 million. For additional information about derivative activity, see Note 3.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts.

Item 4. Controls and Procedures

Our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, they each concluded that our disclosure controls and procedures were effective as of June 30, 2019.

There were no changes in the Company’s internal control over financial reporting during the second quarter of 2019 that materially affected, or were reasonably likely to materially affect, the Company’s internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 4 to the condensed consolidated financial statements in Part I of this Form 10-Q and Note 7 to our consolidated financial statements for the year ended December 31, 2018 included in the Annual Report.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. A discussion of such risks and uncertainties may be found under the heading “Item 1A. Risk Factors” in our Annual Report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds and Issuer Purchases of Equity Securities

Stock Repurchase Program

On December 13, 2018, our Board of Directors announced it had adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock they authorized initial repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and we are not obligated to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

For the three months ended June 30, 2019, we repurchased 1,000,000 shares at an average price of $10.90 per share for $10.9 million, which is reflected as treasury stock. The Company has repurchased a total of 3,648,823 shares under the stock repurchase program for $39.2 million as of June 30, 2019.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
April 1 - 30, 2019	—	$ —	—	$ —
May 1 - 31, 2019	927,588	$ 10.90	927,588	$ 10,108,000
June 1 - 30, 2019	72,412	$ 10.91	72,412	$ 790,000
Total	1,000,000	$ 10.90	1,000,000	$ 10,898,000

Item 6. Exhibits

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.2	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Exhibit 3.2 of Form 8-K filed July 30, 2018)
3.3	Second Amended and Restated Bylaws of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.3 of Form 8-K filed July 30, 2018)
3.4	Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.5	Certificate of Amendment to Certificate of Designation (incorporated by reference to Exhibit 3.1 of Form 8-K filed July 30, 2018)
31.1*	Section 302 Certification of Chief Executive Officer
31.2*	Section 302 Certification of Chief Financial Officer
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer
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 Data Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

GLOSSARY OF COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms that may be used in this report, which are commonly used in the oil and natural gas industry:

"*Adjusted EBITDA*" is a non-GAAP financial measure defined as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including gains and losses on sale of assets, restructuring costs and reorganization items.

"*Adjusted G&A*" or "*Adjusted General and Administrative Expenses*" is a non-GAAP financial measure defined as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense.

"*Adjusted Net Income (Loss)*" is a non-GAAP financial measure defined as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate.

"*API*" gravity means the relative density, expressed in degrees, of petroleum liquids based on a specific gravity scale developed by the American Petroleum Institute.

"*basin*" means a large area with a relatively thick accumulation of sedimentary rocks.

"*Bbl*" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"*Bcf*" means one billion cubic feet, which is a unit of measurement of volume for natural gas.

"*BLM*" means the U.S. Bureau of Land Management.

"*Boe*" means barrel of oil equivalent, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

"*Boe/d*" means Boe per day.

"*Break even*" means the Brent price at which we expect to generate positive Levered Free Cash Flow.

"*Brent*" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea.

"*Btu*" means one British thermal unit—a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"*Completion*" means the installation of permanent equipment for the production of oil or natural gas.

"*Condensate*" means a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"*DD&A*" means depreciation, depletion & amortization.

"*Development drilling or Development well*" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"*Diatomite*" means a sedimentary rock composed primarily of siliceous, diatom shells.

"*Differential*" means 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.

"*Downspacing*" means additional wells drilled between known producing wells to better develop the reservoir.

"*Enhanced oil recovery*" means a technique for increasing the amount of oil that can be extracted from a field.

"*EOR*" means enhanced oil recovery.

"*Estimated ultimate recovery*" or "*EUR*" means the sum of reserves remaining as of a given date and cumulative production as of that date. EUR is shown on a combined basis for oil and natural gas.

"*Exploration activities*" means the initial phase of oil and natural gas operations that includes the generation of a prospect or play and the drilling of an exploration well.

"*Field*" means 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.

"*Formation*" means a layer of rock which has distinct characteristics that differ from those of nearby rock.

"*Fracturing*" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks by connecting pores together.

"*Gas*" or "*Natural gas*" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"*Gross Acres*" or "*Gross Wells*" means the total acres or wells, as the case may be, in which we have a working interest.

"*Held by production*" means acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

"*Henry Hub*" is a distribution hub on the natural gas pipeline system in Erath, Louisiana.

"*Hydraulic fracturing*" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability.

"*Horizontal drilling*" means a wellbore that is drilled laterally.

"*ICE*" means Intercontinental Exchange.

"*Infill drilling*" means drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.

"*Injection Well*" means a well in which water, gas or steam is injected, the primary objective typically being to maintain reservoir pressure and/or improve hydrocarbon recovery.

"*IOR*" means improved oil recovery.

"*Leases*" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"*MBbl*" means one thousand barrels of oil, condensate or NGLs.

"*MBoe*" means one thousand barrels of oil equivalent.

"*MBoe/d*" means MBoe per day.

"*Mcf*" means one thousand cubic feet, which is a unit of measurement of volume for natural gas.

"*MMBbl*" means one million barrels of oil, condensate or NGLs.

"*MMBoe*" means one million barrels of oil equivalent.

"*MMBtu*" means one million Btus.

"*MMcf*" means one million cubic feet, which is a unit of measurement of volume for natural gas.

"*MMcf/d*" means MMcf per day.

"*MW*" means megawatt.

"*Net Acres*" or "*Net Wells*" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"*Net revenue interest*" means all of the working interests, less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"*NGL*" means natural gas liquids, which are the hydrocarbon liquids contained within natural gas.

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

"*Operator*" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"*PDNP*" is an abbreviation for proved developed non-producing.

"*PDP*" is an abbreviation for proved developed producing.

"*Permeability*" means the ability, or measurement of a rock's ability, to transmit fluids.

"*Play*" means a regionally distributed oil and natural gas accumulation. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations.

"*Porosity*" means the total pore volume per unit volume of rock.

"*PPA*" is an abbreviation for power purchase agreement.

"*Production costs*" means costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

"*Productive well*" means a well that is producing oil, natural gas or NGLs or that is capable of production.

"*Proppant*" means sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.

"*Prospect*" means a specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

"*Proved developed reserves*" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved developed producing reserves*" means reserves that are being recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*" means the estimated quantities of oil, gas and gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"*Proved undeveloped drilling location*" means a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*" means 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 recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"*PV-10*" is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC-prescribed pricing assumptions for the period. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the company on a comparative basis to other companies and from period to period.

"*Realized price*" means the cash market price less all expected quality, transportation and demand adjustments.

"*Reasonable certainty*" means a high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

"*Recompletion*" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"*Reserves*" means 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. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

"*Resources*" means quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

"*Royalty*" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"*Royalty interest*" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"*SEC Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules based on the unweighted arithmetic average of oil and natural gas prices as of the first day of each of the 12 months ended on the given date.

"*Seismic Data*" means data produced by an exploration method of sending energy waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

"*Spacing*" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Steamflood*" means cyclic or continuous steam injection.

"*Standardized measure*" means discounted future net cash flows estimated by applying year-end prices to the estimated future production of proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Strip Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules with the exception of pricing that is based on average annual forward-month ICE (Brent) oil and NYMEX Henry Hub natural gas contract pricing in effect on a given date to reflect the market expectations as of that date.

"*Undeveloped acreage*" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

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

"*Unproved reserves*" means reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

"*Wellbore*" means the hole drilled by the bit that is equipped for natural resource production on a completed well. Also called well or borehole.

"*Working interest*" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"*Workover*" means maintenance on a producing well to restore or increase production.

"*WTI*" means West Texas Intermediate.

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 thereunto duly authorized.

		BERRY PETROLEUM CORPORATION (Registrant)
Date:	August 8, 2019	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	August 8, 2019	*/s/* M. S. Helm
		Michael S. Helm Chief Accounting Officer (Principal Accounting Officer)

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, A. T. "Trem" Smith, certify that:

1. I have reviewed this quarterly report of Berry Petroleum Corporation (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(s) 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. 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

   c. 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(s) 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 8, 2019

/s/ A.T. Smith

A. T. "Trem" Smith

President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Cary Baetz, certify that:

1. I have reviewed this quarterly report of Berry Petroleum Corporation (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(s) 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. 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

   c. 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(s) 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 8, 2019

/s/ Cary Baetz

Cary Baetz

Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO
PURSUANT TO SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the quarterly report of Berry Petroleum Corporation (the “Company”) for the fiscal period ended June 30, 2019, as filed with the Securities and Exchange Commission on August 8, 2019 (the “Report”), A. T. "Trem" Smith, as Chief Executive Officer of the Company, and Cary Baetz, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge, respectively:

(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 8, 2019

/s/ A. T. Smith

A. T. "Trem" Smith
President and Chief Executive Officer

/s/ Cary Baetz

Cary Baetz
Executive Vice President and
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Berry Petroleum Corporation and will be retained by Berry Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

The certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.