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, 2021
OR

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

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

Berry Corporation (bry)

(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 ☒	Smaller reporting company ☐
Emerging Growth Company ☒			

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

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

Shares of common stock outstanding as of July 31, 2021 80,471,022

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The financial information and certain other information presented in this report 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 this report. In addition, certain percentages presented in this report 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 CORPORATION (bry)
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2021	December 31, 2020
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 74,918	$ 80,557
Accounts receivable, net of allowance for doubtful accounts of $1,715 at June 30, 2021 and $2,215 at December 31, 2020	63,740	52,027
Derivative instruments	11,515	2,507
Other current assets	26,890	19,400
Total current assets	177,063	154,491
Noncurrent assets:		
Oil and natural gas properties	1,478,622	1,412,566
Accumulated depletion and amortization	(294,576)	(235,259)
Total oil and natural gas properties, net	1,184,046	1,177,307
Other property and equipment	114,558	112,145
Accumulated depreciation	(36,187)	(31,368)
Total other property and equipment, net	78,371	80,777
Other noncurrent assets	5,035	7,235
Total assets	$ 1,444,515	$ 1,419,810
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 160,586	$ 151,985
Derivative instruments	61,476	23,321
Total current liabilities	222,062	175,306
Noncurrent liabilities:		
Long-term debt	394,009	393,480
Derivative instruments	4,058	—
Deferred income taxes	538	1,011
Asset retirement obligations	139,181	135,192
Other noncurrent liabilities	6,009	785
Commitments and Contingencies - Note 4		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 85,583,268 and 85,041,581 shares issued; and 80,471,022 and 79,929,335 shares outstanding, at June 30, 2021 and December 31, 2020, respectively)	86	85
Additional paid-in-capital	914,701	915,877
Treasury stock, at cost (5,112,246 shares at June 30, 2021 and December 31, 2020)	(49,995)	(49,995)
Retained deficit	(186,134)	(151,931)
Total stockholders' equity	678,658	714,036
Total liabilities and stockholders' equity	$ 1,444,515	$ 1,419,810

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

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 147,775	$ 70,515	$ 283,040	$ 192,613
Electricity sales	6,888	4,884	16,957	10,345
(Losses) gains on oil and gas sales derivatives	(55,653)	(42,267)	(109,157)	168,962
Marketing revenues	121	292	2,355	745
Other revenues	118	29	255	53
Total revenues and other	99,249	33,453	193,450	372,718
Expenses and other:				
Lease operating expenses	45,543	40,733	107,827	91,485
Electricity generation expenses	4,712	3,022	12,360	6,968
Transportation expenses	1,757	1,789	3,333	3,611
Marketing expenses	44	280	2,271	710
General and administrative expenses	16,065	18,777	33,135	38,114
Depreciation, depletion, and amortization	35,850	37,512	69,690	72,841
Impairment of oil and gas properties	—	—	—	289,085
Taxes, other than income taxes	11,603	10,449	21,160	14,801
(Gains) losses on natural gas purchase derivatives	(11,639)	925	(39,369)	12,960
Other operating expenses (income)	42	(1,192)	841	1,010
Total expenses and other	103,977	112,295	211,248	531,585
Other (expenses) income:				
Interest expense	(8,217)	(8,676)	(16,702)	(17,596)
Other, net	(8)	(6)	(151)	(12)
Total other (expenses) income	(8,225)	(8,682)	(16,853)	(17,608)
Loss before income taxes	(12,953)	(87,524)	(34,651)	(176,475)
Income tax (benefit) expense	(72)	(22,623)	(448)	3,726
Net loss	$ (12,881)	$ (64,901)	$ (34,203)	$ (180,201)
Net loss per share:				
Basic	$ (0.16)	$ (0.81)	$ (0.43)	$ (2.26)
Diluted	$ (0.16)	$ (0.81)	$ (0.43)	$ (2.26)

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

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Six-Month Period Ended June 30, 2020				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Deficit	Total Stockholders' Equity
	(in thousands)				
December 31, 2019	$ 85	$ 901,830	$ (49,995)	$ 120,528	$ 972,448
Shares withheld for payment of taxes on equity awards and other	—	(794)	—	—	(794)
Stock based compensation	—	3,036	—	—	3,036
Dividends declared on common stock, $0.12/share	—	—	—	(9,564)	(9,564)
Net loss	—	—	—	(115,300)	(115,300)
March 31, 2020	85	904,072	(49,995)	(4,336)	849,826
Shares withheld for payment of taxes on equity awards and other	—	(140)	—	—	(140)
Stock based compensation	—	4,730	—	—	4,730
Net loss	—	—	—	(64,901)	(64,901)
June 30, 2020	$ 85	$ 908,662	$ (49,995)	$ (69,237)	$ 789,515

	Six-Month Period Ended June 30, 2021				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Deficit	Total Stockholders' Equity
	(in thousands)				
December 31, 2020	$ 85	$ 915,877	$ (49,995)	$ (151,931)	$ 714,036
Shares withheld for payment of taxes on equity awards and other	—	(1,442)	—	—	(1,442)
Stock based compensation	—	3,995	—	—	3,995
Issuance of common stock	1	—	—	—	1
Dividends declared on common stock, $0.04/share	—	(3,474)	—	—	(3,474)
Net loss	—	—	—	(21,322)	(21,322)
March 31, 2021	86	914,956	(49,995)	(173,253)	691,794
Shares withheld for payment of taxes on equity awards and other	—	(78)	—	—	(78)
Stock based compensation	—	3,042	—	—	3,042
Dividends declared on common stock, $0.04/share	—	(3,219)	—	—	(3,219)
Net loss	—	—	—	(12,881)	(12,881)
June 30, 2021	$ 86	$ 914,701	$ (49,995)	$ (186,134)	$ 678,658

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

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

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (34,203)	$ (180,201)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	69,690	72,841
Amortization of debt issuance costs	2,728	2,681
Impairment of oil and gas properties	—	289,085
Stock-based compensation expense	6,639	7,501
Deferred income taxes	(473)	2,750
(Decrease) increase in allowance for doubtful accounts	(500)	1,200
Other operating expenses	142	317
Derivative activities:		
Total losses (gains)	69,788	(156,002)
Cash settlements on derivatives	(36,581)	71,499
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(11,189)	21,802
(Increase) in other assets	(7,490)	(3,642)
Increase (decrease) in accounts payable and accrued expenses	3,406	(32,102)
(Decrease) in other liabilities	(2,098)	(11,307)
Net cash provided by operating activities	59,859	86,422
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(67,030)	(56,403)
Changes in capital expenditures accruals	6,934	(7,256)
Acquisition of properties and equipment and other	(825)	(2,076)
Proceeds from sale of property and equipment and other	409	217
Net cash used in investing activities	(60,512)	(65,518)
Cash flows from financing activities:		
Borrowings under RBL credit facility	—	222,550
Repayments on RBL credit facility	—	(223,100)
Dividends paid on common stock	(3,466)	(19,420)
Shares withheld for payment of taxes on equity awards and other	(1,520)	(934)
Net cash used in financing activities	(4,986)	(20,904)
Net increase in cash and cash equivalents	(5,639)	—
Cash and cash equivalents:		
Beginning	80,557	—
Ending	$ 74,918	$ —

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

Note 1—Basis of Presentation

"Berry Corp." refers to Berry Corporation (bry), 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 in February 2017 and its common stock began trading on NASDAQ under the symbol "bry" in July 2018. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located onshore in the United States (the "U.S."), in California (primarily in the San Joaquin basin), 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. 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 Quarterly Report on 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, 2020.

Reclassification

We reclassified certain prior year amounts in the cash flow statements to conform to the current year presentation. These reclassifications had no material impact on the financial statements.

Recently Adopted Accounting Standards

In December 2019, the FASB issued rules which simplify the accounting for income taxes. We adopted these rules in the first quarter of 2021 which did not have a material impact on our financial statements.

Note 2—Debt

The following table summarizes our outstanding debt:

	June 30, 2021	December 31, 2020	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ —	variable rates 3.0% (2021) and 4.0% (2020), respectively	July 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	400,000			
Less: Debt Issuance Costs	(5,991)	(6,520)			
Long-Term Debt, net	$ 394,009	$ 393,480			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At June 30, 2021 and December 31, 2020, debt issuance costs for the RBL Facility (as defined below) reported in “other noncurrent assets” on the balance sheet were approximately $5 million and $7 million net of amortization, respectively. At June 30, 2021 and December 31, 2020, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the “2026 Notes”) reported in “Long-Term Debt, net” on the balance sheet were approximately $6 million and $7 million, respectively.

For the three months ended June 30, 2021 and 2020, the amortization expense for the RBL Facility and 2026 Notes were both approximately $1 million and was included in “interest expense” in the condensed consolidated statements of operations. For each of the six month periods ended June 30, 2021 and 2020, the amortization expense for both the RBL Facility and 2026 Notes was approximately $3 million.

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 Notes was approximately $408 million and $337 million at June 30, 2021 and December 31, 2020, respectively.

The RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“RBL Facility”). The RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. The RBL Facility has an elected commitment feature that allows us to increase commitments to the amount of our borrowing base with lender approval. In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants noted below.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral. The RBL Facility contains certain anti-cash hoarding provisions, including the requirement to repay outstanding loans on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $30 million; and further limits to dividends and share repurchases. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of June 30, 2021, our Leverage Ratio and Current Ratio were 2.1 to 1.0 and 2.2 to 1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of June 30, 2021.

The RBL Facility permits us to repurchase equity and indebtedness, among other things, if availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.5 to 1.0.

As of June 30, 2021, we had no borrowings outstanding, $7 million in letters of credit outstanding, and approximately $193 million of available borrowings capacity under the RBL Facility.

Bond Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any bonds under this program.

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.

The RBL Facility permits Berry LLC to make distributions to Berry Corp. so long as both before and after giving pro forma effect to such distribution no default or borrowing base deficiency exists, availability equals or exceeds 20% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.5 to 1.0. The conditions are currently met with significant margin.

Note 3—Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted oil and gas production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices, which addresses our market risk. We target covering our operating expenses and a majority of our fixed charges, which includes capital needed to sustain production levels, as well as interest and dividends as applicable, with the oil and gas sales hedges for a period of up to two years out. 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.

For fixed-price oil and gas sales swaps, we are the seller, so we make settlement payments for prices above the indicated weighted-average price per barrel and per mmbtu, respectively, and receive settlement payments for prices below the indicated weighted-average price per barrel and per mmbtu, respectively.

For fixed-price 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.

We use oil and gas swaps and puts to protect our sales against decreases in oil and gas prices. We also use swaps to protect our natural gas purchases against increases in 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. The changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil and gas sales hedges are classified in the revenues and other section of the statement of operations, while natural gas purchase hedges are included in expenses and other section of the statement of operations.

As of June 30, 2021, we had the following crude oil production and gas purchase hedges.

	Q3 2021	Q4 2021	FY 2022
Fixed Price Oil Swaps (Brent):			
Hedged volume (mbbls)	1,318	1,318	1,095
Weighted-average price ($/bbl)	$ 48.66	$ 48.66	$ 60.00
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (mmbtu)	4,830,000	2,085,000	—
Weighted-average price ($/mmbtu)	$ 2.83	$ 2.95	$ —

As of June 30, 2021 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 mmbtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period July 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of $1 million. This gain will be cash settled in 2021 as the positions expire.

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, 2021 and December 31, 2020:

	June 30, 2021			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 20,876	$ (9,361)	$ 11,515
Liabilities:				
Commodity Contracts	Current liabilities	(70,837)	9,361	(61,476)
Commodity Contracts	Non-current liabilities	(4,058)	—	(4,058)
Total derivatives		$ (54,019)	$ —	$ (54,019)

	December 31, 2020			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 15,217	$ (12,710)	$ 2,507
Liabilities:				
Commodity Contracts	Current liabilities	(36,031)	12,710	(23,321)
Total derivatives		$ (20,814)	$ —	$ (20,814)

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit 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 the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, or injunctive or declaratory relief.

We accrue 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 a material balance at June 30, 2021 or December 31, 2020. 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 accruals 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, 2021, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We will continue to defend the matter vigorously, however, given the uncertainty of litigation and the stage of the case, among other things, at this time we cannot estimate the likelihood or an amount of possible loss, that may result from this action.

We recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that will reduce our exposure to fuel gas purchase price fluctuations. These capacity agreements are for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Torres Lawsuit") in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (the "Defendants"). The complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company's business, operational efficiency and stability, and compliance policies, that artificially inflated the Company's stock price, resulting in injury to the purported class members when the value of Berry Corp.'s common stock declined following release of its financial results for the third quarter of 2020. The complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys' fees and costs.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Note 5—Equity

Cash Dividends

Our Board of Directors approved a regular cash dividend of $0.04 per share on our common stock for the first and second quarters of 2021. We paid the first and the second quarter cash dividend in April and July 2021, respectively. The Board of Directors approved a $0.06 per share regular cash dividend on our common stock for the third quarter of 2021, which is expected to be paid in October 2021.

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 at the time, they authorized repurchases of up to $50 million under the program. The Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in 2018 and 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. 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 Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. We have not repurchased any shares under the stock repurchase program since 2019.

Stock-Based Compensation

In February 2021, the Company granted awards of 1,832,941 shares of restricted stock units ("RSUs"), which will vest annually in equal amounts over three years and 997,840 performance-based restricted stock units ("PSUs"), which will cliff vest, if at all, at the end of a three year performance period. The fair value of these awards was approximately $14 million.

The RSUs awarded in February 2021 are solely time-based awards. Of the PSUs awarded in February 2021, (a) 50% of such will vest, if at all, based on a total stockholder return ("TSR") performance metric (the "TSR PSUs"), which is defined as the capital gains per share of stock plus dividends paid assuming reinvestment, with TSR measured on an absolute basis and relative to the TSR of the 39 exploration and production companies in the Vanguard World Fund - Vanguard Energy ETF Index plus the S&P SmallCap 600 Value Index (collectively, the "Peer Group") during the performance period; and (b) the other 50% of such will vest, if at all, based on the Company's average cash returned on invested capital ("CROIC PSUs") over the performance period. Depending on the results achieved during the 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 250% of the TSR PSUs granted and from 0% to 200% of the CROIC PSUs granted.

The fair value of the RSUs and CROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Peer Group over the performance periods. The expected volatility of the Company's common stock at the date of grant was estimated based on average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the then current annualized declared dividend. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate 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, 2021	December 31, 2020
	(in thousands)	
Prepaid expenses	$ 12,544	$ 3,592
Materials and supplies	10,847	11,666
Oil inventories	3,273	3,490
Other	226	652
Total other current assets	$ 26,890	$ 19,400

Other non-current assets at June 30, 2021 and December 31, 2020, included approximately $5 million and $7 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, 2021	December 31, 2020
	(in thousands)	
Accounts payable-trade	$ 11,820	$ 11,055
Accrued expenses	56,223	43,452
Royalties payable	17,522	15,150
Greenhouse gas liability - current portion	29,060	35,554
Taxes other than income tax liability	11,439	10,118
Accrued interest	10,500	10,783
Dividends payable	3,217	—
Asset retirement obligations - current portion	20,000	25,000
Other	805	873
Total accounts payable and accrued expenses	$ 160,586	$ 151,985

The increase of $4 million in the long-term portion of the asset retirement obligations from $135 million at December 31, 2020 to $139 million at June 30, 2021 was due to $5 million of accretion, $1 million of liabilities incurred and reclassification of $5 million from current to long-term portion due to changes in anticipated spending and regulatory requirements. These increases were partially offset by $7 million of liabilities settled during the period.

Other non-current liabilities at June 30, 2021 and December 31, 2020 included approximately $5 million and no greenhouse gas liability, respectively.

Supplemental Information on the Statement of Operations

For the three months ended June 30, 2021, other operating expense mainly consisted of $2 million of supplemental property tax assessments and royalty audit charges, mostly offset by $2 million of employee retention credits. For three months ended June 30, 2020, other operating income was $1 million and mainly consisted of sales tax and bankruptcy-related refunds, partially offset by excess abandonment costs and drilling rig standby charges.

For the six months ended June 30, 2021 and 2020 other operating expenses were $1 million. For the six months ended June 30, 2021, other operating expenses mainly consisted of approximately $3 million of supplemental property tax assessments and royalty audit charges and tank rental costs, partially offset by $2 million of employee retention credits. For the six months ended June 30, 2020, other operating expense mainly consist of excess abandonment costs, drilling rig standby charges, partially offset by sales tax and bankruptcy-related refunds.

Supplemental Cash Flow Information

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

	Six Months Ended June 30,	
	2021	2020
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 1,437	$ 911
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 14,925	$ 15,527
Income taxes payments	$ —	$ 2

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. As part of our cash management system, we use a controlled disbursement account to fund cash distribution checks presented for payment by the holder. Checks issued but not yet presented to banks may result in overdraft balances for accounting purposes and have been included in “accounts payable and accrued expenses” in the condensed consolidated balance sheets, amounts are approximately $2 million as of June 30, 2021 and December 31, 2020.

Note 7—Earnings Per Share

We calculate basic earnings (loss) per share by dividing net income (loss) by the weighted-average number of common shares outstanding for each period presented. 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.

The RSUs and PSUs are not a participating security as the dividends are forfeitable. For the three and six months ended June 30, 2021 and 2020, no incremental RSUs or PSUs were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands except per share amounts)			
Basic EPS calculation				
Net loss	$ (12,881)	$ (64,901)	$ (34,203)	$ (180,201)
Weighted-average shares of common stock outstanding	80,471	79,795	80,294	79,702
Basic loss per share	$ (0.16)	$ (0.81)	$ (0.43)	$ (2.26)
Diluted EPS calculation				
Net loss	$ (12,881)	$ (64,901)	$ (34,203)	$ (180,201)
Weighted-average shares of common stock outstanding	80,471	79,795	80,294	79,702
Dilutive effect of potentially dilutive securities[1]	—	—	—	—
Weighted-average common shares outstanding - diluted	80,471	79,795	80,294	79,702
Diluted loss per share	$ (0.16)	$ (0.81)	$ (0.43)	$ (2.26)

(1) We excluded approximately 2.9 million and 0.8 million dilutive securities from the dilutive weighted-average common shares outstanding for the three months ended June 30, 2021 and 2020, because their effect was anti-dilutive. We excluded approximately 2.6 million and 0.8 million dilutive securities from the dilutive weighted-average common shares outstanding for the six months ended June 30, 2021 and 2020, because their effect was anti-dilutive.

Note 8—Revenue Recognition

We derive most of our revenue from sales of oil, natural gas and NGLs, with the remaining revenue generated from sales of electricity and marketing activities related to transporting and marketing third-party volumes.

The following table provides disaggregated revenue for the three and six months ended June 30, 2021 and 2020:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands)			
Oil sales	$ 141,309	$ 67,512	$ 263,668	$ 185,822
Natural gas sales	5,415	2,834	17,492	6,202
Natural gas liquids sales	1,051	169	1,880	589
Electricity sales	6,888	4,884	16,957	10,345
Marketing revenues	121	292	2,355	745
Other revenues	118	29	255	53
Revenues from contracts with customers	154,902	75,720	302,607	203,756
(Losses) gains on oil and gas sales derivatives	(55,653)	(42,267)	(109,157)	168,962
Total revenues and other	$ 99,249	$ 33,453	$ 193,450	$ 372,718

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, 2020 (the “*Annual Report*”*) filed with the Securities and Exchange Commission (*“*SEC*”*). When we use the terms* “*we,*” “*us,*” “*our,*” “*Berry,*” *the* “*Company*” *or similar words in this report, we are referring to, as the context may require, (i) Berry Corporation (bry), a Delaware corporation (formerly known as Berry Petroleum Corporation, and also referred to herein as* “*Berry Corp.*”*) together with its wholly owned subsidiary, Berry Petroleum, LLC, a Delaware limited liability company (also referred to herein as* “*Berry LLC*”*), or (ii) either Berry Corp. or Berry LLC.*

Our Company

We are a western United States independent upstream energy company focused on the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California.

In the aggregate, our assets are characterized by high oil content. The overwhelming majority of our productive assets are located in the oil-rich reservoirs in the San Joaquin basin of California, which has more than 150 years of production history and substantial remaining oil in place. As a result of the substantial data produced over the basin’s long history, its reservoir characteristics are well understood, which enables predictable, repeatable, low geological risk and low-cost development opportunities. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. We also have assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah and in the low geologic risk natural gas resource play in the Piceance basin in Colorado. We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling locations with attractive full-cycle economics will support our objectives to generate “Levered Free Cash Flow” (a non-GAAP financial measure discussed under “How We Plan and Evaluate Operations” in this report) to fund our operations, optimize capital efficiency, and return capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles.

We have a progressive approach to evolving and growing the business in today's dynamic oil and gas industry. Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize our assets, create value for shareholders, and support environmental goals that align with a more positive future.

How We Plan and Evaluate Operations

We use “Levered Free Cash Flow” in planning our capital allocation to sustain production levels and fund internal growth opportunities, as well as determine hedging needs. Levered Free Cash Flow is a non-GAAP financial measure that we define as Adjusted EBITDA less capital expenditures, interest expense, and dividends. Adjusted EBITDA is also a non-GAAP financial measure that is discussed and defined below.

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) 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. Adjusted EBITDA is a non-GAAP financial measure that we define as earnings before interest expense; income taxes; depreciation, depletion, and amortization (“DD&A”); derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual and infrequent items.

Operating Expenses

Overall, operating expense is used by management as a measure of the efficiency with which operations are performed. 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. Marketing revenues represent sales of natural gas purchased from and sold to third parties. 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 with gas hedges.

Environmental, Health & Safety

Like other companies in the oil and gas industry, our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Current and future laws and regulations, as well as legislative and regulatory changes and other government activities, can materially impact our exploration, development, production and abandonment plans, including by restricting the production rate of oil, natural gas and NGLs below the rate that would otherwise be possible. Additionally, the regulatory burden on the industry increases the cost of doing business and consequently effects capital expenditures and earnings.

As part of our commitment to creating long-term stockholder value, we strive to conduct our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate and our other stakeholders in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with existing laws and regulations. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics, including with respect to health and safety and spill prevention, is a part of our short-term incentive program 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 and approximately 10% of such costs are capitalized, which is significantly less than industry norms. 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.

Business Environment, Market Conditions and Outlook

Our operating and financial results, same as those of the oil and gas industry as a whole, are heavily influenced by commodity prices. Oil and gas prices and differentials have, and may continue to, fluctuate significantly as a result of numerous market-related variables, including global geopolitical and economic conditions. Our 2020 operating and financial results were adversely impacted by the deterioration and prolonged weakness in commodity prices that resulted from the COVID-19 pandemic as well as from certain actions by foreign oil and gas producers. Oil prices began to improve toward the end of 2020 and further strengthened in the first half of 2021.

The extent to which our full year 2021 operating and financial results, or that of future periods, will be adversely impacted by the ongoing COVID-19 pandemic and the actions of foreign oil and gas producers will depend largely on future developments, which are highly uncertain and cannot be accurately predicted. Further, to what extent these events do ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors that are not within our control and cannot be predicted, including the duration and extent of the pandemic and speculation as to future actions by Saudi Arabia, Russia and other foreign producers. We have taken steps and continue to work to address the challenges and mitigate repercussions from both the COVID-19 pandemic and further industry downturns on our operations, our financial condition and our people.

The recovery in the oil and gas industry has improved with increasing oil prices as more states and countries re-open and national and global economies continue to recover. The demand for oil, while improving, could again decline if there is a widespread resurgence of the COVID-19 outbreak, although the extent of the additional impact on our industry and our business cannot be reasonably predicted at this time. In July 2021, OPEC+ reached an agreement to continue gradually increasing oil production through the end of 2022, as global demand grows.

As a result of the 2020 industry downturn, commodity price outlook, and increasing uncertainty, we heightened our focus on driving operational efficiencies and reducing costs. As a result of our ability to accomplish this goal we reinstated a quarterly dividend in the first quarter of 2021, which was increased for the third quarter of 2021.

Commodity Pricing and Differentials

Our revenue, costs, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production, as well as the prices we pay for our natural gas purchases, which are affected by a variety of factors, including those discussed in Part II, Item 1A. “Risk Factors” in this Quarterly Report, as well as in Part I, Item 1A. “Risk Factors” in our Annual Report.

Average oil prices were higher for the three months ended June 30, 2021 compared to the three months ended March 31, 2021 and June 30, 2020. Brent crude oil contract prices ranged between $62.15 per bbl and $76.18 per bbl during the second quarter of 2021. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. As described above, if reactions to the COVID-19 pandemic cause demand to worsen, and/or if OPEC+ producers take actions that again create a supply surge, and if necessary storage availability is not sufficient, oil prices may again go materially lower.

In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $7.56 per mmbtu and as low as $2.37 per mmbtu during the second quarter of 2021, while we paid an average of $3.31 per mmbtu in this period.

The following table presents the average Brent, WTI, Kern, Delivered, and Henry Hub prices for the three months ended June 30, 2021, March 31, 2021 and June 30, 2020 and for the six months ended June 30, 2021 and June 30, 2020:

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
Oil (bbl) – Brent	$ 69.08	$ 61.32	$ 33.39	$ 65.23	$ 42.10
Oil (bbl) – WTI	$ 66.03	$ 57.82	$ 28.42	$ 61.95	$ 37.38
Natural gas (mmbtu) – Kern, Delivered	$ 3.23	$ 7.99	$ 1.45	$ 5.60	$ 1.73
Natural gas (mmbtu) – Henry Hub	$ 2.95	$ 3.50	$ 1.70	$ 3.22	$ 1.80

As mentioned above, California oil prices are Brent-influenced as California refiners import approximately 65% to 70% of the state's demand from OPEC+ countries and other waterborne sources. Without the higher costs and potential environmental impact 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, in appropriate oil price environments, should continue to allow us to realize positive cash margins in California over the cycle.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for Utah's unique oil characteristics and the remoteness of the assets makes access to other markets logistically challenging. However, we have high operational control of our existing acreage, which provides significant upside for additional vertical and or horizontal development and recompletions.

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 California steamfloods and cogeneration facilities than we produce and sell in the Rockies. Additionally, in recent history, the California gas markets have generally had higher gas prices than the Rockies and the rest of the United States. Consequently, higher gas prices have a negative impact on our operating results. 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. We also strive to minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of such gas purchases. We recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that will reduce our exposure to fuel gas purchase price fluctuations. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies.

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 which are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

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 short and long-term contracts with terms ending in September 2021 through December 2026. The contract ending in September 2021 represents less than 30% of our electricity sales in the six months ended June 30, 2021. The most significant input and cost of the cogeneration facilities is natural gas. We generally receive significantly more revenue from these cogeneration facilities in the summer months, most notably in June through September, due to negotiated capacity payments we receive.

EH&S and Regulatory Matters

Like other companies in the oil and gas industry, our operations are subject to complex and stringent federal, state, and local laws and regulations relating to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water use, land use, managing greenhouse gases or other emissions, protection of health, safety and the environment, protection of air quality, and the transportation, marketing, and sale of our products. Congress and federal and state agencies frequently revise the safety and environmental laws and regulations applicable to our operations, and any changes that result in more stringent and costly requirements for the oil and natural gas industry, for example for waste handling, disposal, cleanup and abandonment, could have a significant impact on operating and financial results. In many of these areas, federal, state, and local agencies may assert overlapping authority and regulations. In addition, new laws and regulations could apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors have no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

As part of our commitment to creating long-term stockholder value, we strive to conduct our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate, and our other stakeholders in order to help ensure that we can realize the full potential of our resources in a manner that safeguards people and the environment and complies with existing laws and regulations. We monitor our environmental, health and safety, or EH&S, performance through various measures, and we hold our employees and contractors to high standards. Meeting corporate EH&S metrics, including with respect to EH&S incidents and spill prevention, is a part of our short-term incentive program for all employees. In 2020, we achieved a Total Recordable Incident Rate, or TRIR, of 0.5, which we believe, based on available data, is a record company low and is below the United States average for all industries, which is a TRIR of 3.0 based on the most recently available data.

Certain actions of the new U.S. administration could negatively impact the oil and gas industry. Such actions may include, among other things, the increased regulation of greenhouse gas emissions associated with oil and gas operations, the imposition of a new carbon tax on greenhouse gas emissions and replacing tax incentives related to fossil fuel with incentives for clean energy production. Such outcomes could materially and adversely affect our business, results of operations and financial condition.

Additionally, in California, the jurisdiction, duties and enforcement authority of various state agencies have significantly increased with respect to oil and natural gas activities in recent years, and these state agencies, as well as certain cities and counties, have significantly revised their regulations, regulatory interpretations and data collection and reporting requirements. Certain state legislators have recently sought to introduce new legislation to restrict oil and gas activities in California, however, those efforts have not been successful to date. Additionally, California Governor Gavin Newsome has advocated for and directed actions, including through executive orders, to restrict the oil and gas operations and reduce both the supply and demand for oil and gas in the state. Most recently, for example:

- On April 23, 2021, Governor Newsom directed the California Geologic Energy Management Division (“CalGEM”) of the Department of Conservation, California's primary regulator of the oil and natural gas industry on private and state lands, to initiate rulemaking to halt the issuance of new permits for well stimulation treatments by 2024. It remains unclear whether or not CalGEM has existing statutory authority to take such action or whether additional enabling legislation from the California State Legislature is required. The directive also instructed the California Air Resources Board to evaluate regulatory pathways for phasing out oil extraction by 2045 under the state’s climate change scoping plan, which is the state’s comprehensive, programmatic plan to achieve the state’s required reductions in GHG emissions. We cannot predict the ultimate outcome of this evaluation, but authority for any rulemaking to broadly prohibit the extraction of oil would likely require the introduction of new legislation and be subject to significant opposition. As noted above, other proposals to prohibit or restrict certain oil extraction methods have previously been unsuccessful in the California State Legislature.

- In response to Governor Newsom's April 23 directive explained above, in May 2021, CalGEM published pre-rulemaking draft regulations prohibiting authorizations for well stimulation treatments after January 1, 2024. Well stimulation treatments covered by the draft rule include hydraulic fracturing, acid fracturing, acid-matrix stimulation, and other well-stimulation treatments that enhance oil and gas production by creating channels in rock formations for hydrocarbons to flow. Separately, in July 2021, CalGEM denied a set of permits for hydraulic fracturing requested by an operator, generally citing the protection of public health and safety and environmental quality. While the operator has indicated it will appeal this decision, we cannot predict the ultimate outcome of any such appeal, and CalGEM could issue similar permit denials in the future for other operators. Given the limited use of hydraulic fracturing in our operations in California currently, we do not expect to be materially impacted by a potential final rule from CalGEM. However, our current operations and future plans may be impacted by pending or threatened legislative, regulatory changes or other government activity impacting the timing of, and conditions imposed on, the required permits and approvals governing our activities.

Violations and liabilities with respect to any of the applicable laws and regulations, including those related to any environmental incident, could result in significant administrative, civil, or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, an inability to receive permits, operational interruptions or shutdowns and other liabilities. Additionally, the costs of remedying any environmental incident may be significant, and remediation obligations could adversely affect our financial condition, results of operations and prospects. For additional information, please see Part I, Item 1 "Regulation of Health, Safety and Environmental Matters", as well as Part I, Item 1.A. "Risk Factors" in our Annual Report.

For additional information, please see Part I, Item 1 "Regulation of Health, Safety and Environmental Matters", as well as Part I, Item 1.A. "Risk Factors" in our Annual Report.

Seasonality

Seasonal weather conditions can impact our drilling and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling and completion 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 have been and in the future 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.

Natural gas prices fluctuate based on seasonal and other market-related impacts. We purchase significantly more gas than we sell to generate steam and electricity in our cogeneration facilities for our producing activities. As a result, our key exposure to gas prices is in our costs. We mitigate a substantial portion of this exposure by selling excess electricity from our cogeneration operations to third parties. The pricing of these electricity sales is closely tied to the purchase price of natural gas. These sales are generally higher in the summer months as they include seasonal capacity amounts. We also hedge a significant portion of the gas we expect to consume and we recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our operations in California.

Capital Expenditures

For the three and six months ended June 30, 2021, our capital expenditures were approximately $43 million and $67 million, respectively, on an accrual basis including capitalized overhead and interest and excluding acquisitions and asset retirement spending. Approximately 78% and 14% of total capital for the six months ended June 30, 2021 was directed to California oil and Utah operations, respectively .

Our planned 2021 capital expenditure budget is approximately $120 to $130 million. We plan to spend the majority of this amount during the second and third quarters of 2021. We expect our capital expenditures will result in essentially flat year-over year production and a higher exit rate for 2021 than 2020. We currently anticipate oil production will be approximately 89% of total production in 2021, compared to 88% in 2020. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2021 capital development programs with cash flow from operations and, if necessary, current cash on hand, which was generated during 2020 and anticipated for use to supplement our 2021 capital program. We plan to live within Levered Free Cash Flow in 2021 and beyond.

The amount and timing of capital expenditures are within our control and subject to our discretion, and due to the speed with which we are able to drill and complete our wells in California, capital may be adjusted quickly during the year depending on numerous factors, including commodity prices, storage constraints, supply/demand considerations and attractive rates of return. We believe it is important to retain the flexibility to defer planned capital expenditures and may do so based 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 receipt and timing of required regulatory permits and approvals, the availability of necessary equipment, infrastructure and capital, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners, as well as general market conditions. Any postponement or elimination of our development drilling program could result in a reduction of proved reserves volumes and materially affect our business, financial condition and results of operations. Additionally and not included in the capital expenditures noted above, for the full year 2021, we plan to spend approximately $19 million to $23 million on plugging and abandonment activities, including satisfying our annual obligations under the California Idle Well Management Program.

Summary by Area

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

($ in thousands, except prices)	California (San Joaquin and Ventura basins) Three Months Ended June 30, 2021	March 31, 2021	June 30, 2020
Oil, natural gas and natural gas liquids sales	$ 129,128	$ 113,177	$ 62,943
Operating income[1]	$ 11,413	$ 18,965	$ 32,469
Depreciation, depletion, and amortization (DD&A)	$ 35,174	$ 32,896	$ 36,518
Average daily production (mboe/d)	21.7	21.9	23.4
Production (oil % of total)	100 %	100 %	100 %
Realized sales prices:			
Oil (per bbl)	$ 65.37	$ 57.34	$ 29.53
NGLs (per bbl)	$ —	$ —	$ —
Gas (per mcf)	$ —	$ —	$ —
Capital expenditures[2]	$ 31,303	$ 22,760	$ 16,446

($ in thousands, except prices)	Utah (Uinta basin) Three Months Ended June 30, 2021	March 31, 2021	June 30, 2020	Colorado (Piceance basin) Three Months Ended June 30, 2021	March 31, 2021	June 30, 2020
Oil, natural gas and natural gas liquids sales	$ 16,199	$ 15,889	$ 6,439	$ 2,438	$ 6,194	$ 1,132
Operating income (loss)[1]	$ 6,736	$ 7,433	$ (584)	$ 1,121	$ 5,039	$ 6
Depreciation, depletion, and amortization (DD&A)	$ 630	$ 554	$ 905	$ 38	$ 38	$ 43
Average daily production (mboe/d)	4.4	4.0	4.4	1.2	1.2	1.3
Production (oil % of total)	52 %	49 %	49 %	2 %	2 %	2 %
Realized sales prices:						
Oil (per bbl)	$ 58.55	$ 52.08	$ 23.11	$ 56.05	$ 25.80	$ 20.67
NGLs (per bbl)	$ 29.61	$ 26.81	$ 5.82	$ —	$ —	$ —
Gas (per mcf)	$ 3.30	$ 6.65	$ 1.68	$ 3.53	$ 9.83	$ 1.53
Capital expenditures[2]	$ 9,162	$ 392	$ 81	$ —	$ 1	$ 145

(1) Operating income (loss) includes oil, natural gas and NGL sales, and scheduled oil derivative settlements, offset by operating expenses (as defined elsewhere), general and administrative expenses, DD&A, impairment of oil and gas properties, and taxes, other than income taxes.

(2) Excludes corporate capital expenditures.

Production and Prices

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

	Three Months Ended		
	June 30, 2021	March 31, 2021	June 30, 2020
Average daily production:[1]			
Oil (mbbl/d)	24.0	23.9	25.6
Natural Gas (mmcf/d)	17.5	16.9	19.2
NGL (mbbl/d)	0.4	0.3	0.3
Total (mboe/d)[2]	27.3	27.1	29.1
Total Production:			
Oil (mbbl)	2,183	2,151	2,330
Natural gas (mmcf)	1,595	1,517	1,746
NGLs (mbbl)	36	31	29
Total (mboe)[2]	2,485	2,435	2,650
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 64.72	$ 56.89	$ 28.98
Effects of scheduled derivative settlements ($/bbl)	$ (18.33)	$ (12.08)	$ 25.42
Oil with hedges ($/bbl)	$ 46.39	$ 44.81	$ 54.40
Natural gas ($/mcf)	$ 3.39	$ 7.96	$ 1.62
NGL ($/bbl)	$ 29.61	$ 26.81	$ 5.82
Average Benchmark prices:			
Oil (bbl) – Brent	$ 69.08	$ 61.32	$ 33.39
Oil (bbl) – WTI	$ 66.03	$ 57.82	$ 28.42
Natural gas (mmbtu) – Kern, Delivered[3]	$ 3.23	$ 7.99	$ 1.45
Natural gas (mmbtu) – Henry Hub[4]	$ 2.95	$ 3.50	$ 1.70

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $69.08 per bbl and $2.95 per mmbtu.

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

(4) Henry Hub is the relevant index used for gas sales in the Rockies.

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

	Three Months Ended		
	June 30, 2021	March 31, 2021	June 30, 2020
Average daily production (mboe/d):[(1)]			
California	21.7	21.9	23.4
Utah	4.4	4.0	4.4
Colorado	1.2	1.2	1.3
Total average daily production	27.3	27.1	29.1

(1) Production represents volumes sold during the period.

Average daily production increased 0.2 mboe/d, or 1%, and Company wide oil production increased 0.1 mboe/d, for the three months ended June 30, 2021, compared to the three months ended March 31, 2021, largely due to increased development capital in Utah, where we generated a 10% increase in production. Of the 58 wells drilled in the second quarter of 2021, 44 were production wells, eight were injector wells and six were delineation, a slight increase compared to the well count of 50 in the first quarter of 2021. However, 21 of the 58 wells drilled will not come on production until the third quarter of 2021. Development drilling in the second quarter 2021 included eight wells drilled in Utah, which require more capital than our typical California wells, as well as increased California workover, equipping and facilities work.

Our California production of 21.7 mboe/d for the second quarter 2021 decreased 1% from the first quarter 2021. California production has been negatively impacted by a loss of our production from one of Berry's locations where lower water withdrawals by an offset operator along with a reduction in our steam injection volumes triggered a drop in production. The issue has reduced production by approximately 600 bbl/d and this will impact all of 2021. However, the steam is expected to recharge and be back to historical production levels by early next year.

Average daily production decreased 6% for the three months ended June 30, 2021 as compared to the three months ended June 30, 2020 due to significantly lower development capital spending in the first quarter of 2021 compared to the first quarter of 2020, as well as lower spending in the full year 2020 compared to the full year 2019.

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

	Six Months Ended	
	June 30, 2021	June 30, 2020
Average daily production:[1]		
Oil (mbbl/d)	23.9	26.5
Natural Gas (mmcf/d)	17.2	18.8
NGL (mbbl/d)	0.4	0.3
Total (mboe/d)[2]	27.2	29.9
Total Production:		
Oil (mbbl)	4,334	4,815
Natural gas (mmcf)	3,113	3,430
NGLs (mbbl)	66	61
Total (mboe)[2]	4,919	5,448
Weighted-average realized sales prices:		
Oil without hedges ($/bbl)	$ 60.83	$ 38.59
Effects of scheduled derivative settlements ($/bbl)	$ (15.22)	$ 17.30
Oil with hedges ($/bbl)	$ 45.61	$ 55.89
Natural gas ($/mcf)	$ 5.62	$ 1.81
NGL ($/bbl)	$ 28.30	$ 9.66
Average Benchmark prices:		
Oil (bbl) – Brent	$ 65.23	$ 42.10
Oil (bbl) – WTI	$ 61.95	$ 37.38
Gas (mmbtu) – Kern, Delivered[3]	$ 5.60	$ 1.73
Natural gas (mmbtu) – Henry Hub[4]	$ 3.22	$ 1.80

(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, during the six months ended June 30, 2021, the average prices of Brent oil and Henry Hub natural gas were $65.23 per bbl and $3.22 per mmbtu respectively.

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

(4) Henry Hub is the relevant index used for gas sales in the Rockies.

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

	Six Months Ended	
	June 30, 2021	June 30, 2020
Average daily production (mboe/d):[(1)]		
California	21.8	24.1
Utah	4.2	4.5
Colorado	1.2	1.3
Total average daily production	27.2	29.9

(1) Production represents volumes sold during the period.

Average daily production decreased 9% for the six months ended June 30, 2021, compared to the six months ended June 30, 2020, largely due to a lack of development in 2020, compared to 2019, and natural decline. Our California production of 21.8 mboe/d for the six months ended June 30, 2021 decreased 10% compared to the six months ended June 30, 2020. Of the 100 California wells drilled in the first half of 2021, 81 were producing wells, 11 were delineation wells and 8 were injector wells.

Results of Operations

Three Months Ended June 30, 2021 compared to Three Months Ended March 31, 2021.

	Three Months Ended			
	June 30, 2021	March 31, 2021	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 147,775	$ 135,265	$ 12,510	9 %
Electricity sales	6,888	10,069	(3,181)	(32)%
Losses on oil and gas sales derivatives	(55,653)	(53,504)	(2,149)	4 %
Marketing and other revenues	239	2,371	(2,132)	(90)%
Total revenues and other	$ 99,249	$ 94,201	$ 5,048	5 %

Revenues and Other

Oil, natural gas and NGL sales increased by $13 million, or 9%, to approximately $148 million for the three months ended June 30, 2021, compared to the three months ended March 31, 2021. The increase was driven by $17 million and $2 million higher unhedged oil prices and oil sales volumes, respectively, partially offset by $7 million of lower unhedged natural gas prices.

In the first quarter of 2021, the United States experienced a sharp, and unusually large increase in natural gas prices caused by an unprecedented February demand spike from Winter Storm Uri that impacted much of the nation. This had a dramatic impact on both our natural gas and electricity sales, driving significant revenue increases in the first quarter. The impact on our fuel gas cost in California was not nearly as pronounced due to our effective hedging program and our proactive reduction in fuel usage during the highly volatile period in February.

Electricity sales represent sales to utilities, and decreased $3 million, or 32%, to approximately $7 million for the three months ended June 30, 2021 compared to the three months ended March 31, 2021. Revenue declined from the first quarter when gas prices, which typically drive revenue, were unusually high due to the increased demand from Winter Storm Uri. Gas prices and electricity unit sales returned to their typical seasonal levels in the second quarter 2021.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended June 30, 2021 was $40 million and the loss for the three months ended March 31, 2021 was $26 million. The quarter-over-quarter increase in settlement losses was driven by higher oil prices relative to the derivative fixed prices in the second quarter compared to those of the first quarter of 2021. The average derivative fixed price of $45.82 and notional volumes of 19 mbbl/d were unchanged when compared to the first quarter 2021.The mark-to-market non-cash loss of $16 million for the three months ended June 30, 2021 was due to higher futures prices relative to the derivative fixed prices at June 30, 2021 compared to the non-cash loss of $28 million for the three months ended March 31, 2021. In the second half of 2021 our daily oil hedged volumes will decrease approximately 25%, and have slightly higher fixed prices than in the first half of 2021.

Marketing and other revenues decreased by $2 million for the three months ended June 30, 2021 when compared to the three months ended March 31, 2021 due to the unusually high unit prices caused by the demand spike from Winter Storm Uri in the first quarter of 2021.

	Three Months Ended June 30, 2021	Three Months Ended March 31, 2021	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 45,543	$ 62,284	$ (16,741)	(27)%
Electricity generation expenses	4,712	7,648	(2,936)	(38)%
Transportation expenses	1,757	1,576	181	11 %
Marketing expenses	44	2,227	(2,183)	(98)%
General and administrative expenses	16,065	17,070	(1,005)	(6)%
Depreciation, depletion and amortization	35,850	33,840	2,010	6 %
Taxes, other than income taxes	11,603	9,557	2,046	21 %
Gains on natural gas purchase derivatives	(11,639)	(27,730)	16,091	(58)%
Other operating expenses	42	799	(757)	(95)%
Total expenses and other	103,977	107,271	(3,294)	(3)%
Other (expenses) income:				
Interest expense	(8,217)	(8,485)	268	(3)%
Other, net	(8)	(143)	135	(94)%
Loss before income taxes	(12,953)	(21,698)	8,745	(40)%
Income tax benefit	(72)	(376)	304	(81)%
Net loss	$ (12,881)	$ (21,322)	$ 8,441	(40)%
Expenses per boe:[1]				
Lease operating expenses	$ 18.33	$ 25.58	$ (7.25)	(28)%
Electricity generation expenses	1.90	3.14	(1.24)	(39)%
Electricity sales[1]	(2.77)	(4.13)	1.36	(33)%
Transportation expenses	0.70	0.65	0.05	8 %
Transportation sales[1]	(0.05)	(0.06)	0.01	(17)%
Marketing expenses	0.02	0.92	(0.90)	(98)%
Marketing revenues[1]	(0.05)	(0.92)	0.87	(95)%
Derivatives settlements received for gas purchases[1]	(0.77)	(10.78)	10.01	(93)%
Total operating expenses	$ 17.31	$ 14.40	$ 2.91	20 %
Total unhedged operating expenses[2]	$ 18.08	$ 25.18	$ (7.10)	(28)%
Total non-energy operating expenses[3]	$ 12.71	$ 12.74	$ (0.03)	— %
Total energy operating expenses[4]	$ 4.60	$ 1.66	$ 2.94	177 %
General and administrative expenses[5]	$ 6.46	$ 7.01	$ (0.55)	(8)%
Depreciation, depletion and amortization	$ 14.43	$ 13.90	$ 0.53	4 %
Taxes, other than income taxes	$ 4.67	$ 3.93	$ 0.74	19 %

(1) 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.

(2) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(3) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlement (gains) losses.

(4) Total energy operating expenses equals fuel and gas purchase derivative settlement (gains) losses less electricity sales.

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.11 per boe and $1.51 per boe for the three months ended June 30, 2021 and March 31, 2021, respectively.

Expenses and Other

In accordance with GAAP, we report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues. 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 are defined above in “How We Plan and Evaluate Operations”, which include electricity revenues. In the first quarter of 2021 we experienced a sharp, and unprecedented increase in natural gas prices caused by a demand spike from Winter Storm Uri that impacted much of the nation in February. For about one week in mid-February, daily gas prices exceeded $100 per mmbtu and during this time we temporarily modified our operations to reduce the amount of fuel gas required to be purchased, thereby avoiding approximately $7 million of additional costs. Compared to the first quarter 2021, our hedges on fuel gas purchases had a smaller effect in the second quarter, resulting in higher fuel gas costs, hedged, by $4 million. Combined with the $3 million lower electricity sales, operating expenses were higher by 20%, or $2.91 per boe and $8 million on an absolute dollar basis in the second quarter 2021 compared to the first quarter 2021. Fuel purchases were hedged 85% and 79% in the first quarter and second quarter, respectively. We were, and remain during 2021, largely hedged on our natural gas purchases against increases in purchase prices.

Unhedged lease operating expenses per boe decreased to $18.33, for the three months ended June 30, 2021, a 28% or $7.25 per boe decrease compared to $25.58 per boe for the three months ended March 31, 2021 driven by $8.43 per boe of lower unhedged fuel costs for our California steam operations. Unhedged average fuel purchase price decreased $3.62 per mmbtu to $3.31 per mmbtu in the second quarter 2021 compared to the unusually high prices caused by Winter Storm Uri in the three months ended March 31, 2021. Non-energy operating expense decreased $0.03 per boe as a result of lower outside services, well maintenance and facility costs, partially offset by higher lease overhead and chemicals. Even with rising prices in 2021, we have held non-energy costs down following the cost savings efforts which began in 2020. Lease operating expenses include fuel, maintenance, labor including supervision, vehicles, workover expenses, field office, and tools and supplies. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased approximately 39% to $1.90 per boe for the three months ended June 30, 2021, compared to $3.14 per boe for the three months ended March 31, 2021 due to lower natural gas costs described above. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Gains and losses on natural gas purchase derivatives resulted in a $12 million gain for the three months ended June 30, 2021 and a gain of $28 million in the three months ended March 31, 2021. Settlement gains for each of the three months ended June 30, 2021 and March 31, 2021 were $2 million or $0.77 per boe and $26 million, or $10.78 per boe, respectively, and decreased due to lower gas prices which came off unprecedented highs in the first quarter of 2021 from Winter Storm Uri. The mark-to-market valuation gain for the three months ended June 30, 2021 was $10 million compared to a $2 million gain for the prior quarter. Generally, because we are the fixed price payer on these natural gas swaps, increases in the associated futures prices will result in valuation gains.

Transportation expense increased slightly to $0.70 per boe for the three months ended June 30, 2021 compared to $0.65 per boe for the three months ended March 31, 2021.

Marketing expenses decreased by $0.90 per boe for the three months ended June 30, 2021 when compared to the three months ended March 31, 2021 due to the unprecedented natural gas purchase prices caused by the demand spike from Winter Storm Uri in the first quarter of 2021.

General and administrative expenses decreased by $1.0 million, or 6%, to $16.1 million for the three months ended June 30, 2021, compared to the three months ended March 31, 2021, due to the following matters and those noted in adjusted general and administrative expenses below. For the three months ended June 30, 2021 and March 31, 2021, general and administrative expenses included non-cash stock compensation costs of approximately $2.8 million and $3.7 million, respectively. We had no non-recurring costs in the first half of 2021. Approximately 10% of our overhead is capitalized and thus excluded from general and administrative expenses.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased 1% to $13.3 million for the three months ended June 30, 2021 compared to $13.4 million for the three months ended March 31, 2021. On a per boe basis, adjusted general and administrative expenses decreased to $5.35 per boe from $5.50 per boe in the first quarter 2021 due to the impact of higher production. Please see "—Non-GAAP Financial Measures" for a reconciliation of adjusted general and administrative expense to general and administrative expenses, the most directly comparable financial measures calculated and presented in accordance with GAAP.

DD&A increased by $2 million or 6% to approximately $36 million for the three months ended June 30, 2021 compared to the three months ended March 31, 2021. This increase is due to increased production and higher depletion rates from our periodic re-evaluation of these estimates.

Taxes, Other Than Income Taxes

	Three Months Ended			
	June 30, 2021	March 31, 2021	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.97	$ 0.99	$ (0.02)	(2)%
Ad valorem and property taxes	1.99	2.01	(0.02)	(1)%
Greenhouse gas allowances	1.71	0.93	0.78	84 %
Total taxes other than income taxes	$ 4.67	$ 3.93	$ 0.74	19 %

Taxes, other than income taxes, increased in the three months ended June 30, 2021 by $0.74 per boe, or 19%, to $4.67. Greenhouse gas ("GHG") costs were higher in the second quarter of 2021 due to higher mark-to-market valuations.

Other Operating Expenses

Other operating expenses for the three months ended June 30, 2021 was less than $0.1 million and mainly consisted of $2 million of supplemental property tax assessments and royalty audit charges and $2 million of employee retention credits. Other operating expenses of $1 million for the three months ended March 31, 2021 comprised mainly of additional storage capacity, obtained in response to global oil storage concerns, along with prior years royalty audit charges.

Interest Expense

Interest expense was relatively flat at $8 million for each of the three months ended June 30, 2021 and March 31, 2021.

Income Tax Benefit

Our effective tax rate was approximately 1% and 2% for the three months ended June 30, 2021 and March 31, 2021, respectively. The rates in each quarter were impacted by the valuation allowance recorded due to the estimated future realizability of deferred tax assets.

Three Months Ended June 30, 2021 compared to Three Months Ended June 30, 2020.

	Three Months Ended June 30,			
	2021	2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 147,775	$ 70,515	$ 77,260	110 %
Electricity sales	6,888	4,884	2,004	41 %
Losses on oil and gas sales derivatives	(55,653)	(42,267)	(13,386)	32 %
Marketing and other revenues	239	321	(82)	(26)%
Total revenues and other	$ 99,249	$ 33,453	$ 65,796	197 %

Revenues and Other

Oil, natural gas and NGL sales increased by $77 million, or 110% to approximately $148 million for the three months ended June 30, 2021 when compared to the three months ended June 30, 2020. This variance was driven by $81 million of higher unhedged commodity prices, partially offset by lower volumes.

Electricity sales represent sales to utilities, and increased by $2.0 million, or 41%, to approximately $7 million for the three months ended June 30, 2021 when compared to the three months ended June 30, 2020. The increase was largely due to higher unit sales prices driven by higher natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended June 30, 2021 was $40 million compared to the gain for the three months ended June 30, 2020 of $59 million. The quarter-over-quarter change from settlement gains to losses was driven by higher oil prices in the second quarter 2021 and lower oil prices in the second quarter 2020 relative to our derivative fixed prices. The mark-to-market non-cash loss of $16 million for the three months ended June 30, 2021 was due to higher futures prices relative to our derivative fixed contract prices at June 30, 2021. The mark-to-market non-cash loss of $101 million for the three months ended June 30, 2020, was due to higher futures prices relative to the derivative fixed prices at June 30, 2020.

Marketing and other revenues were comparable for the periods presented.

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 45,543	$ 40,733	$ 4,810	12 %
Electricity generation expenses	4,712	3,022	1,690	56 %
Transportation expenses	1,757	1,789	(32)	(2)%
Marketing expenses	44	280	(236)	(84)%
General and administrative expenses	16,065	18,777	(2,712)	(14)%
Depreciation, depletion and amortization	35,850	37,512	(1,662)	(4)%
Taxes, other than income taxes	11,603	10,449	1,154	11 %
(Gains) losses on natural gas purchase derivatives	(11,639)	925	(12,564)	n/a
Other operating expenses (income)	42	(1,192)	1,234	(104)%
Total expenses and other	103,977	112,295	(8,318)	(7)%
Other (expenses) income:				
Interest expense	(8,217)	(8,676)	459	(5)%
Other, net	(8)	(6)	(2)	33 %
Loss before income taxes	(12,953)	(87,524)	74,571	(85)%
Income tax benefit	(72)	(22,623)	22,551	(100)%
Net loss	$ (12,881)	$ (64,901)	$ 52,020	(80)%
Expenses per boe:[(1)]				
Lease operating expenses	$ 18.33	$ 15.37	$ 2.96	19 %
Electricity generation expenses	1.90	1.14	0.76	67 %
Electricity sales[(1)]	(2.77)	(1.84)	(0.93)	51 %
Transportation expenses	0.70	0.67	0.03	4 %
Transportation sales[(1)]	(0.05)	(0.01)	(0.04)	400 %
Marketing expenses	0.02	0.11	(0.09)	(82)%
Marketing revenues[(1)]	(0.05)	(0.11)	0.06	(55)%
Derivatives settlements (received) paid for gas purchases[(1)]	(0.77)	2.78	(3.55)	(128)%
Total operating expenses	$ 17.31	$ 18.11	$ (0.80)	(4)%
Total unhedged operating expenses[(2)]	$ 18.08	$ 15.33	$ 2.75	18 %
Total non-energy operating expenses[(3)]	$ 12.71	$ 12.81	$ (0.10)	(1)%
Total energy operating expenses[(4)]	$ 4.60	$ 5.30	$ (0.70)	(13)%
General and administrative expenses[(5)]	$ 6.46	$ 7.09	$ (0.63)	(9)%
Depreciation, depletion and amortization	$ 14.43	$ 14.16	$ 0.27	2 %
Taxes, other than income taxes	$ 4.67	$ 3.94	$ 0.73	19 %

(1) 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.

(2) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(3) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlement (gains) losses.

(4) Total energy operating expenses equals fuel and gas purchase derivative settlement (gains) losses less electricity sales.

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.11 per boe and $1.77 per boe for the three months ended June 30, 2021 and June 30, 2020, respectively.

Expenses and Other

On a hedged basis, operating expenses, decreased by 4% or $0.80 per boe to $17.31 per boe for the second quarter 2021 compared to $18.11 per boe for the second quarter 2020. The decrease was due to lower energy operating expense of $0.70 per boe and lower non-energy operating expense of $0.10 per boe.

Unhedged lease operating expenses were $18.33 per boe for the three months ended June 30, 2021, a 19% or $2.96 per boe increase compared to $15.37 for the three months ended June 30, 2020 driven by an 87% or $3.78 per boe higher unhedged fuel costs, for our California steam operations. Unhedged average fuel purchase price increased $1.57 to $3.31 per mmbtu in the second quarter 2021 compared to $1.74 per mmbtu in the second quarter 2020. Non-energy operating expense declined $0.10 per boe compared to the second quarter of 2020. These decreases included lower facilities costs and outside services, partially offset by higher well maintenance and recompletion activities.

Electricity generation expenses increased approximately 67% to $1.90 per boe for the three months ended June 30, 2021 from $1.14 per boe for the same period in 2020 due to the previously discussed higher natural gas costs. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains and losses on natural gas purchase derivatives for the three months ended June 30, 2021 and June 30, 2020 resulted in a gain of $12 million and a loss of $1 million, respectively. Settlements for each of the three months ended June 30, 2021 and 2020, were $2 million or $0.77 per boe of gain and $7 million or $2.78 per boe of loss, driven by higher gas prices in 2021 compared to 2020. The mark-to-market valuation gain for the three months ended June 30, 2021 was $10 million compared to $6 million of gain for the same period in 2020, consistent with the changes in futures prices at the end of each period. Because we are the fixed price payer on these natural gas swaps, generally, increases in the associated price index creates valuation gains.

Transportation expenses remained essentially flat for the three months ended June 30, 2021 and June 30, 2020.

Marketing expenses decreased to $0.02 per boe for the three months ended June 30, 2021, compared to $0.11 per boe for the three months ended June 30, 2020, mostly due to lower gas prices.

General and administrative expenses decreased $3 million, or 14%, to approximately $16 million for the three months ended June 30, 2021 compared to the three months ended June 30, 2020. For the three months ended June 30, 2021 and June 30, 2020, general and administrative expenses included non-cash stock compensation costs of approximately $2.8 million and $4.4 million, respectively, with no non-recurring costs in 2021 and $0.3 million in 2020.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased 6% to $13.3 million for the three months ended June 30, 2021 compared to $14.1 million for the three month periods ended June 30, 2020. The decrease was primarily due to lower professional service expenses and employee costs.

DD&A decreased $2 million, or 4%, to approximately $36 million for the three months ended June 30, 2021 compared to the three months ended June 30, 2020, primarily due to 6% lower sales volumes compared to the same period in 2020. On a per boe basis, period-over-period DD&A increased $0.27 to $14.43 from $14.16 due to higher depletion rates during the second quarter of 2021, compared to the second quarter 2020.

Taxes, Other Than Income Taxes

	Three Months Ended June 30,			
	2021	2020	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.97	$ 0.70	$ 0.27	39 %
Ad valorem and property taxes	1.99	1.39	0.60	43 %
Greenhouse gas allowances	1.71	1.85	(0.14)	(8)%
Total taxes other than income taxes	$ 4.67	$ 3.94	$ 0.73	19 %

Taxes, other than income taxes increased 19% to $4.67 per boe for the three months ended June 30, 2021 compared to $3.94 per boe for the three months ended June 30, 2020. Severance taxes increased from the prior year due to higher Utah revenue. Ad valorem and property taxes increased due to higher California tax assessments. Greenhouse gas allowances declined from the second quarter of 2020 as a result of opportunistic allowance purchases and an increase in state allocated allowances for 2021 which more than offset higher mark-to-market valuations.

Other Operating Expenses (Income)

Other operating expense for the three months ended June 30, 2021 was less than $0.1 million and mainly consisted of $2 million of supplemental property tax assessments and royalty audit charges and $2 million of employee retention credits. Other operating income for the three months ended June 30, 2020 were $1 million and comprised mainly of sales tax and bankruptcy-related refunds, partially offset by excess abandonment costs and drilling rig standby charges.

Interest Expense

Interest expense was comparable in the three months ended June 30, 2021 and June 30, 2020.

Income Tax Benefit

Our effective tax rate was approximately 1% for the three months ended June 30, 2021 compared to 26% for the three months ended June 30, 2020. The rate in the second quarter 2021 was impacted by the valuation allowance recorded due to the estimated future realizability of deferred tax assets.

Six Months Ended June 30, 2021 compared to Six Months Ended June 30, 2020.

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 283,040	$ 192,613	$ 90,427	47 %
Electricity sales	16,957	10,345	6,612	64 %
(Losses) gains on oil and gas sales derivatives	(109,157)	168,962	(278,119)	n/a
Marketing and other revenues	2,610	798	1,812	227 %
Total revenues and other	$ 193,450	$ 372,718	$ (179,268)	(48)%

Revenues and Other

Oil, natural gas and NGL sales increased by $90 million, or 47% to approximately $283 million for the six months ended June 30, 2021 when compared to the six months ended June 30, 2020. The increase was driven by $108 million attributable to higher commodity prices, partially offset by lower oil volumes.

Electricity sales which represent sales to utilities increased $7 million or 64% to $17 million for the six months ended June 30, 2021 when compared to the six months ended June 30, 2020. The increase was mostly due to higher unit sales prices that were driven by higher natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement losses of $66 million and gains of $83 million for the six months ended June 30, 2021 and June 30, 2020, respectively. The period over period shift from settlement gains to settlement losses was driven by higher oil prices relative to the derivative fixed prices in the six months ended June 30, 2021, compared to lower oil prices relative to the derivatives fixed prices in the six months ended June 30, 2020. The mark-to-market non-cash loss of $43 million for the six months ended June 30, 2021 was due to higher futures prices relative to the derivative fixed prices at June 30, 2021. The gain of $86 million for the six months ended June 30, 2020, was primarily due to lower futures prices relative to the derivative fixed prices at June 30, 2020.

Marketing and other revenues were higher for the six months ended June 30, 2021, compared to the six months ended June 30, 2020 due to higher average gas prices.

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 107,827	$ 91,485	$ 16,342	18 %
Electricity generation expenses	12,360	6,968	5,392	77 %
Transportation expenses	3,333	3,611	(278)	(8)%
Marketing expenses	2,271	710	1,561	220 %
General and administrative expenses	33,135	38,114	(4,979)	(13)%
Depreciation, depletion and amortization	69,690	72,841	(3,151)	(4)%
Impairment of oil and gas properties	—	289,085	(289,085)	100 %
Taxes, other than income taxes	21,160	14,801	6,359	43 %
(Gains) losses on natural gas purchase derivatives	(39,369)	12,960	(52,329)	n/a
Other operating expenses	841	1,010	(169)	(17)%
Total expenses and other	211,248	531,585	(320,337)	(60)%
Other (expenses) income:				
Interest expense	(16,702)	(17,596)	894	(5)%
Other, net	(151)	(12)	(139)	1,158 %
Loss before income taxes	(34,651)	(176,475)	141,824	(80)%
Income tax (benefit) expense	(448)	3,726	(4,174)	(112)%
Net loss	$ (34,203)	$ (180,201)	$ 145,998	(81)%
Expenses per boe:[1]				
Lease operating expenses	$ 21.92	$ 16.79	$ 5.13	31 %
Electricity generation expenses	2.51	1.28	1.23	96 %
Electricity sales[1]	(3.45)	(1.90)	(1.55)	82 %
Transportation expenses	0.68	0.66	0.02	3 %
Transportation sales[1]	(0.05)	(0.01)	(0.04)	400 %
Marketing expenses	0.46	0.13	0.33	254 %
Marketing revenues[1]	(0.48)	(0.13)	(0.35)	269 %
Derivatives settlements (received) paid for gas purchases[1]	(5.72)	2.16	(7.88)	n/a
Total operating expenses	$ 15.87	$ 18.98	$ (3.11)	(16)%
Total unhedged operating expenses[2]	$ 21.59	$ 16.82	$ 4.77	28 %
Total non-energy operating expenses[3]	$ 12.73	$ 13.44	$ (0.71)	(5)%
Total energy operating expenses[4]	$ 3.14	$ 5.54	$ (2.40)	(43)%
General and administrative expenses[5]	$ 6.74	$ 7.00	$ (0.26)	(4)%
Depreciation, depletion and amortization	$ 14.17	$ 13.37	$ 0.80	6 %
Taxes, other than income taxes	$ 4.30	$ 2.72	$ 1.58	58 %

(1) 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.

(2) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(3) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlement (gains) losses.

(4) Total energy operating expenses equals fuel and gas purchase derivative settlement (gains) losses less electricity sales.

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.31 per boe and $1.74 per boe for the six months ended June 30, 2021 and June 30, 2020, respectively.

Expenses and Other

On a hedged basis, operating expenses, decreased 16% or $3.11 per boe to $15.87 for the six months ended June 30, 2021 from $18.98 per boe for the six months ended June 30, 2020. Our continuing emphasis on cost savings and efficiency initiatives, which began in the second quarter of 2020, demonstrated meaningful results in the first half of 2021 compared to the first half of 2020 as non-energy costs declined 5% or $0.71 per boe to $12.73 per boe.

Unhedged lease operating expenses were $21.92 per boe for the six months ended June 30, 2021, a 31% or $5.13 per boe increase compared to $16.79 for the six months ended June 30, 2020 driven by $7.03 per boe higher unhedged fuel costs, for our California steam operations. Unhedged average fuel purchase price doubled to $12.31 per mmbtu in the six months ended June 30, 2021 compared to the six months ended June 30, 2020. The key non-energy operating expense decreases included lower facilities costs and outside services, partially offset by higher well maintenance and recompletion activities.

Electricity generation expenses increased approximately 96% to $2.51 per boe for the six months ended June 30, 2021 from $1.28 per boe for the same period in 2020 due to the previously discussed higher natural gas costs. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains and losses on natural gas purchase derivatives for the six months ended June 30, 2021 and June 30, 2020 resulted in a gain of $39 million and a loss of $13 million, respectively. The settlement gain for the six months ended June 30, 2021 was $28 million, or $5.72 per boe, compared to a settlement loss of $12 million, or $2.16 per boe for same period in 2020, driven by higher gas prices in 2021 compared to 2020. The mark-to-market valuation gain for the six months ended June 30, 2021 was $12 million compared to $1 million of loss for the same period in 2020, consistent with the changes in future prices at the end of each period. Because we are the fixed price payer on these natural gas swaps, generally, increases in the associated price index creates valuation gains.

Transportation expenses were comparable for the periods presented.

Marketing expenses increased to $0.46 per boe for the six months ended June 30, 2021, compared to $0.13 per boe for the six months ended June 30, 2020 largely due to higher prices from the February natural gas demand spike caused by Winter Storm Uri.

General and administrative expenses decreased $5 million, or 13%, to approximately $33 million for the six months ended June 30, 2021 compared to the six months ended June 30, 2020. For the six months ended June 30, 2021 and June 30, 2020, general and administrative expenses included non-cash stock compensation costs of approximately $6 million and $7 million, respectively, and no non-recurring costs during the six months ended June 30, 2021, and $2 million during the same period in 2020.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased $2 million, or 7% to $27 million for the six months ended June 30, 2021 compared to $29 million for the six months ended June 30, 2020. The year-over-year decrease was primarily due to lower professional service expenses and employee costs.

DD&A decreased $3 million, or 4%, to approximately $70 million for the six months ended June 30, 2021 compared to the six months ended June 30, 2020, primarily due to lower sales volumes compared to the same period in 2020. On a per boe basis, period-over-period DD&A increased $0.80 to $14.17 from $13.37 due to higher depletion rates in 2021, compared to 2020.

Impairment of oil and gas properties

We recorded a non-cash pre-tax asset impairment charge of $289 million on properties in Utah and certain California locations for the six months ended June 30, 2020.

Taxes, Other Than Income Taxes

	Six Months Ended June 30,			
	2021	2020	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.98	$ 0.71	$ 0.27	38 %
Ad valorem and property taxes	2.00	1.39	0.61	44 %
Greenhouse gas allowances	1.32	0.62	0.70	113 %
Total taxes other than income taxes	$ 4.30	$ 2.72	$ 1.58	58 %

Taxes, other than income taxes increased $1.58 to $4.30 per boe for the six months ended June 30, 2021 compared to $2.72 per boe for the six months ended June 30, 2020. The increase was largely due to higher greenhouse gas mark-to-market valuations at June 30, 2021 and allowance purchases we made at low prices due to a temporary market dislocation in 2020. During 2021, we experienced higher California property tax rates, as well as higher severance taxes due to increased revenues in Utah.

Other Operating Expenses (Income)

Other operating income and expenses for the six months ended June 30, 2021 were net expenses of $1 million and mainly consisted of approximately $3 million of supplemental property tax assessments, royalty audit charges and tank rental costs, partially offset by $2 million of employee retention credits. For the six months ended June 30, 2020, other operating expense mainly consist of excess abandonment costs, drilling rig standby charges, partially offset by refunds in 2020.

Interest Expense

Interest expense was comparable in the six months ended June 30, 2021 and June 30, 2020.

Income Tax (Benefit) Expense

Our effective tax rate was 1% and (2)% for the six months ended June 30, 2021 and June 30, 2020, respectively. The rates in 2021 and 2020 were negatively impacted as we recorded valuation allowances on a large portion of our tax credits, net operating loss carryforwards and on other deferred tax assets as a result of estimated future realizability.

Non-GAAP Financial Measures

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

Adjusted Net Income (Loss) is not a measure of net income (loss), Levered Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either, in all cases, as determined by GAAP. Adjusted EBITDA, Levered Free Cash Flow and Adjusted Net Income (Loss) 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 and infrequent 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 to sustain production levels and for 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 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 and infrequent 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 and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs. 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, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
			(in thousands)		
Adjusted EBITDA reconciliation to net loss:					
Net loss	$ (12,881)	$ (21,322)	$ (64,901)	$ (34,203)	$ (180,201)
Add (Subtract):					
Interest expense	8,217	8,485	8,676	16,702	17,596
Income tax (benefit) expense	(72)	(376)	(22,623)	(448)	3,726
Depreciation, depletion and amortization	35,850	33,840	37,512	69,690	72,841
Impairment of oil and gas properties	—	—	—	—	289,085
Losses (gains) on derivatives	44,014	25,774	43,192	69,788	(156,002)
Net cash (paid) received for scheduled derivative settlements	(37,431)	850	51,874	(36,581)	71,499
Other operating expense (income)	42	799	(1,192)	841	1,010
Stock compensation expense	2,860	3,779	4,579	6,639	7,501
Non-recurring costs	—	—	316	—	2,178
Adjusted EBITDA	$ 40,599	$ 51,829	$ 57,433	$ 92,428	$ 129,233

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
			(in thousands)		
Adjusted EBITDA reconciliation to net cash provided by operating activities and Levered Free Cash Flow calculation:					
Net cash provided by operating activities	$ 21,429	$ 38,430	$ 41,939	$ 59,859	$ 86,422
Add (Subtract):					
Cash interest payments	288	14,637	648	14,925	15,527
Cash income tax payments	—	—	—	—	2
Non-recurring costs	—	—	316	—	2,178
Other changes in operating assets and liabilities	18,882	(1,238)	14,530	17,644	25,104
Adjusted EBITDA	$ 40,599	$ 51,829	$ 57,433	$ 92,428	$ 129,233
Subtract:					
Capital expenditures - accrual basis	(43,461)	(23,569)	(16,700)	(67,030)	(56,403)
Interest expense	(8,217)	(8,485)	(8,676)	(16,702)	(17,596)
Cash dividends declared	(3,219)	(3,474)	—	(6,693)	(9,564)
Levered Free Cash Flow[(1)]	$ (14,298)	$ 16,301	$ 32,057	$ 2,003	$ 45,670

(1) Levered Free Cash Flow, as defined by the Company, includes cash paid for scheduled derivative settlements of $37 million for the three months ended June 30, 2021 and cash received for scheduled derivative settlements of $1 million and $52 million, for the three months ended March 31, 2021 and June 30, 2020, respectively. Levered Free Cash Flow, as defined by the Company, includes cash paid for scheduled derivative settlements of $37 million for the six months ended June 30, 2021 and cash received for scheduled derivative settlements of $71 million for the six months ended June 30, 2020.

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, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
			(in thousands)		
Adjusted Net (Loss) Income reconciliation to net loss:					
Net loss	$ (12,881)	$ (21,322)	$ (64,901)	$ (34,203)	$ (180,201)
Add: discrete income tax items	—	—	—	—	46,700
Add (Subtract):					
Losses (gains) on derivatives	44,014	25,774	43,192	69,788	(156,002)
Net cash (paid) received for scheduled derivative settlements	(37,431)	850	51,874	(36,581)	71,499
Other operating expenses (income)	42	799	(1,192)	841	1,010
Impairment of oil and gas properties	—	—	—	—	289,085
Non-recurring costs	—	—	316	—	2,178
Total additions, net	6,625	27,423	94,190	34,048	207,770
Income tax expense of adjustments at effective tax rate[(1)]	(37)	(474)	(24,680)	(511)	(51,485)
Adjusted Net (Loss) Income	$ (6,293)	$ 5,627	$ 4,609	$ (666)	$ 22,784
Basic EPS on Adjusted Net (Loss) Income	$ (0.08)	$ 0.07	$ 0.06	$ (0.01)	$ 0.29
Diluted EPS on Adjusted Net (Loss) Income	$ (0.08)	$ 0.07	$ 0.06	$ (0.01)	$ 0.28
Weighted average shares of common stock outstanding - basic	80,471	80,115	79,795	80,294	79,702
Weighted average shares of common stock outstanding - diluted	80,471	82,276	80,640	80,294	80,545

(1) Excludes discrete income tax items from the total additions, net line item and the tax effect the discrete income tax items have on the current rate.

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, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
General and administrative expenses	$ 16,065	$ 17,070	$ 18,777	$ 33,135	$ 38,114
Subtract:					
Non-cash stock compensation expense (G&A portion)	(2,763)	(3,669)	(4,380)	(6,432)	(7,299)
Non-recurring costs	—	—	(316)	—	(2,178)
Adjusted general and administrative expenses	$ 13,302	$ 13,401	$ 14,081	$ 26,703	$ 28,637
Adjusted general and administrative expenses ($/boe)	$ 5.35	$ 5.50	$ 5.31	$ 5.43	$ 5.26

Liquidity and Capital Resources

Currently, we expect to fund our 2021 capital expenditures with cash flows from our operations, supplemented if necessary by cash on hand resulting from excess Levered Free Cash Flow generated in 2020 and the first quarter of 2021. As of June 30, 2021, we had liquidity of $268 million, consisting of $75 million cash in the bank and borrowing availability of $193 million under our RBL Facility (factoring in $7 million stand-by letters of credit). In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants summarized below. The RBL Facility matures July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms. We also have $400 million in aggregate principal amount 7% senior unsecured notes due February 2026 (the “2026 Notes”) outstanding as further discussed below. We currently believe that our liquidity, capital resources and cash on hand will be sufficient to conduct our business and operations for at least the next 12 months.

We currently expect our operations to continue to generate positive Levered Free Cash Flow for the combined two-year down-cycle that we projected through the end of 2021, based on our current operating plans, the current oil price levels and current hedge positions. We have approximately 55% of our expected oil production hedged in the remainder of 2021 at approximately $49 per bbl, as well as additional oil sales hedges of approximately 3,000 bbl/d at $60 per bbl in 2022. In the longer term, if oil prices were to significantly decline and remain weak through 2021 and longer, we may not be able to continue to generate the same level of Levered Free Cash Flow we are currently generating and our liquidity and capital resources may not be sufficient to conduct our business and operations until commodity prices recover. Please see Part II, Item 1A “Risk Factors” for a discussion of known material risks, many of which are beyond our control, that could adversely impact our business, liquidity, financial condition, and results of operations.

The RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“RBL Facility”). The RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. The RBL Facility has an elected commitment feature that allows us to increase commitments to the amount of our borrowing base with lender approval. In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants noted below.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral. The RBL Facility contains certain anti-cash hoarding provisions, including the requirement to repay outstanding loans on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $30 million; and further limits to dividends and share repurchases. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of June 30, 2021, our Leverage Ratio and Current Ratio were 2.1 to 1.0 and 2.2 to 1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of June 30, 2021.

The RBL Facility permits us to repurchase equity and indebtedness, among other things, if availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.5 to 1.0.

Hedging

We have protected a significant portion of our anticipated cash flows in 2021, as well as a portion in 2022, using our commodity hedging program, including fixed-price derivative contracts. We hedge crude oil and gas production to protect against oil and gas price decreases and we also hedge gas purchases to protect against price increases. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. We expect our operations to generate sufficient cash flows at current commodity prices including our 2021 and 2022 hedging positions. For information regarding risks related to our hedging program, see “Item 1A. Risk Factors—Risks Related to Our Operations and Industry” in our Annual Report.

As of June 30, 2021, we had the following crude oil production and gas purchases hedges.

	Q3 2021	Q4 2021	FY 2022
Fixed Price Oil Swaps (Brent):			
Hedged volume (mbbls)	1,318	1,318	1,095
Weighted-average price ($/bbl)	$ 48.66	$ 48.66	$ 60.00
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (mmbtu)	4,830,000	2,085,000	—
Weighted-average price ($/mmbtu)	$ 2.83	$ 2.95	$ —

As of June 30, 2021 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 mmbtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period July 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of $1 million. This gain will be cash settled in 2021 as the positions expire.

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

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	June 30, 2021	June 30, 2020
Crude Oil (per bbl):					
Realized sales price, before the effects of derivative settlements	$ 64.72	$ 56.89	$ 28.98	$ 60.83	$ 38.59
Effects of derivative settlements	$ (18.33)	$ (12.08)	$ 25.42	$ (15.22)	$ 17.30
Oil with hedges ($/bbl)	$ 46.39	$ 44.81	$ 54.40	$ 45.61	$ 55.89
Purchased Natural Gas (per mmbtu):					
Purchase price, before the effects of derivative settlements	$ 3.31	$ 6.93	$ 1.74	$ 5.08	$ 2.05
Effects of derivative settlements	$ (0.31)	$ (4.51)	$ 1.11	$ (2.36)	$ 0.84
Purchased Natural Gas with hedges	$ 3.00	$ 2.42	$ 2.85	$ 2.72	$ 2.89

Pipeline Commitments

We recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that will reduce our exposure to fuel gas purchase price fluctuations. These capacity agreements are for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million.

Cash Dividends

Our Board of Directors approved a regular cash dividend of $0.04 per share on our common stock for the first and second quarters of 2021. We paid the first and the second quarter cash dividend in April and July 2021, respectively. The Board of Directors approved a $0.06 per share regular cash dividend on our common stock for the third quarter of 2021, which is expected to be paid in October 2021. As of July 31, 2021, the Company has paid approximately $72 million in dividends since the inception of our dividend program following our IPO in the third quarter of 2018. This represents a 65% return of capital from our IPO.

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 at the time, they authorized repurchases of up to $50 million under the program. The Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in 2018 and 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. 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 Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. We have not repurchased any shares under the stock repurchase program since 2019.

Bond Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any bonds under this program.

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.

The RBL Facility permits Berry LLC to make distributions to Berry Corp. so long as both before and after giving pro forma effect to such distribution no default or borrowing base deficiency exists, availability equals or exceeds 20% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.5 to 1.0. The conditions are currently met with significant margin.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30,	
	2021	2020
	(in thousands)	
Net cash:		
Provided by operating activities	$ 59,859	$ 86,422
Used in investing activities	(60,512)	(65,518)
Used in financing activities	(4,986)	(20,904)
Net increase (decrease) in cash and cash equivalents	$ (5,639)	$ —

Operating Activities

Cash provided by operating activities decreased for the six months ended June 30, 2021 by approximately $27 million when compared to the six months ended June 30, 2020, due to a $149 million change in derivatives settlements which consisted of $66 million of oil derivatives settlements paid in the six months ended June 30, 2021 and $83 million of oil derivatives settlements received in the six months ended June 30, 2020 and an increase in taxes, other than income taxes of $6 million. These cash decreases were mostly offset by increased sales of $99 million, a decrease in operating expense of $18 million, a decrease in general and administrative expense of $2 million and working capital changes and other of $9 million.

Investing Activities

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

	Six Months Ended June 30,	
	2021	2020
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (67,030)	$ (56,403)
Changes in capital expenditures accruals	6,934	(7,256)
Acquisition of properties and equipment and other	(825)	(2,076)
Proceeds from sale of properties and equipment and other	409	217
Cash used in investing activities	$ (60,512)	$ (65,518)

Cash used in investing activities decreased $5 million for the six months ended June 30, 2021 when compared to the same period in 2020, primarily due to a decrease in cash used for capital spending. In 2021, we have reinstated our development program, albeit at a lower level than we began 2020.

Financing Activities

Cash used by financing activities decreased $16 million for the six months ended June 30, 2021 when compared to the same period in 2020. In 2021, the cash used was primarily for dividends paid of $3 million. In 2020, the cash used was primarily for dividends paid of $19 million.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2020 to June 30, 2021 are discussed below.

	June 30, 2021		December 31, 2020	
	(in thousands)			
Cash and cash equivalents	$	74,918	$	80,557
Accounts receivable, net	$	63,740	$	52,027
Derivative instruments assets - current and long-term	$	11,515	$	2,507
Other current assets	$	26,890	$	19,400
Property, plant & equipment, net	$	1,262,417	$	1,258,084
Other noncurrent assets	$	5,035	$	7,235
Accounts payable and accrued expenses	$	160,586	$	151,985
Derivative instruments liabilities - current and long-term	$	65,534	$	23,321
Long-term debt	$	394,009	$	393,480
Deferred income taxes liability - long-term	$	538	$	1,011
Asset retirement obligations - long-term	$	139,181	$	135,192
Other noncurrent liabilities	$	6,009	$	785
Stockholders' equity	$	678,658	$	714,036

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

The $12 million increase in accounts receivable was driven by $20 million higher sales period-over-period, partially offset by $8 million lower hedge settlements outstanding at each period-end.

The $33 million increase in net derivative liabilities is due to the change from a net liability of $21 million at December 31, 2020 to a net liability of $54 million as of June 30, 2021. Changes to mark-to-market derivative values at the end of each period result from differences in the forward curve prices relative to the contract fixed prices, changes in positions held and settlements received and paid throughout the periods.

The $7 million increase in other current assets was primarily due to $8 million of prepayments for development permits and other prepaid fees, partially offset by a decrease in materials inventory of $1 million.

The $4 million increase in property, plant and equipment was primarily the result of $68 million in capital investments partially offset by depreciation expense of $64 million.

The $2 million decrease in other noncurrent assets was primarily due to deferred debt issuance cost amortization.

The $9 million increase in accounts payable and accrued expenses included approximately $14 million of increased derivative settlement payables, $6 million increase in capital, a $3 million increase for dividends accrued and a $2 million increase in royalties accrued due to increased sales. The increases were partially offset by a $6 million decrease in the current portion of the greenhouse gas liability, a $5 million decrease due to a reclass in current asset retirement obligations from short term to long term, as well as a $5 million decrease due to bonus payments, net of accruals added.

The increase of $4 million in the long-term portion of the asset retirement obligations from $135 million at December 31, 2020 to $139 million at June 30, 2021 was due to $5 million of accretion and $1 million of liabilities incurred and reclassification of $5 million from current to long-term portion due to changes in anticipated spending and regulatory requirements. These increases were partially offset by $7 million of liabilities settled during the period.

The $5 million increase in other noncurrent liabilities was driven by additional non-current greenhouse gas liabilities in the first quarter of 2021 compared to year end. At year-end 2020 the non-current portion of greenhouse gas liabilities was moved to current.

The $35 million decrease in stockholders' equity was due to the net loss of $34 million, $7 million of common stock dividends declared and $1 million of shares withheld for payment of taxes on equity awards. These decreases were partially offset by $7 million of stock-based equity awards, net of taxes.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiary, are the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, or injunctive or declaratory relief.

We accrue 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 a material balance at June 30, 2021 or December 31, 2020. 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 accruals 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, 2021, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We will continue to defend the matter vigorously, however, given the uncertainty of litigation and the stage of the case, among other things, at this time we cannot estimate the likelihood or an amount of possible loss, that may result from this action.

We recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that will reduce our exposure to fuel gas purchase price fluctuations. These capacity agreements are for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million. We generally have significantly more production than the amounts committed for delivery and have the ability to secure additional volumes of products as needed.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Torres Lawsuit") in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (the "Defendants"). The complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company's business, operational efficiency and stability, and compliance policies, that artificially inflated the Company's stock price, resulting in injury to the purported class members when the value of Berry Corp.'s common stock declined following release of its financial results for the third quarter of 2020. The complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys' fees and costs.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of June 30, 2021:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:					
Processing and transportation contracts[1]	$ 37,280	$ 4,954	$ 8,423	$ 4,317	$ 19,586
Operating lease obligations	10,356	2,048	3,491	3,103	1,714
Other purchase obligations[2]	32,100	15,000	17,100	—	—
Total contractual obligations	$ 79,736	$ 22,002	$ 29,014	$ 7,420	$ 21,300

(1) Amounts include payments which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure transportation of our natural gas production to market, as well as, pipeline and processing.

(2) Amounts include a purchase commitment of $6 million to build a road, which is classified as current. Additionally, we have a drilling commitment in California, for which we are required to drill 97 wells with an estimated total cost of $29 million by April 2023. As of June 30, 2021 we have drilled 10 wells and are required to drill 30 additional wells estimated at $9 million by the end of December 2021.

Critical Accounting Policies and Estimates

See Note 1, Basis of Presentation, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q and Part II, Item 7 “Critical Accounting Policies and Estimates” in the Annual Report on Form 10-K.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this Quarterly Report includes forward-looking statements that involve 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, capital for sustained production levels, 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 below in Part II, Item 1A. “Risk Factors” in this Quarterly Report, as well as in Part I, Item 1A. “Risk Factors” our most recent Annual Report on Form 10-K and other filings with the Securities and Exchange Commission.

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

- the impact of current, pending and/or future laws and regulations, and of legislative and regulatory changes and other government activities, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- the length, scope and severity of the ongoing COVID-19 pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, and storage capacity;
- global economic trends, geopolitical risks and general economic and industry conditions, such as those resulting from the COVID-19 pandemic and from the actions of foreign producers, importantly including OPEC+ and changes in OPEC+'s production levels;
- volatility of oil, natural gas and NGL prices, including the sharp decline in crude oil prices;
- the California and global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;
- supply of and demand for oil, natural gas and NGLs;
- disruptions to, capacity constraints in, or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures, meet our working capital requirements or fund planned investments;
- price fluctuations and availability of natural gas and electricity and the cost of steam;
- our ability to use derivative instruments to manage commodity price risk;
- the regulatory environment, including availability or timing of, and conditions imposed on, obtaining and/or maintaining permits and approvals, including those necessary for drilling and/or development projects;
- our ability to meet our planned drilling schedule, including due to our ability to obtain permits on a timely basis or at all, and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- concerns about climate change and other air quality issues;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- drilling and production results, including lower–than–expected production, reserves or resources from development projects or higher–than–expected decline rates;
- 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;

- uncertainties and liabilities associated with acquired and divested assets;
- 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;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including wildfires, earthquakes and pandemics;
- environmental risks and liabilities under federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyber attacks; and
- governmental actions and political conditions, as well as the actions by other third parties that are beyond our control.

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

As of June 30, 2021, there have been 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 2020 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, certain costs such as fuel gas, and cash flows are likewise affected. Additional non-cash impairment charges for our oil and gas properties may be required if commodity prices experience significant declines.

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 is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, our expected capital and operating costs, 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.

We determine the fair value of our oil and gas sales and natural gas purchase 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, 2021, the fair value of our hedge positions was a net liability of approximately $54 million. A 10% increase in the oil and natural gas index prices above the June 30, 2021 prices would result in a net liability of approximately $87 million; conversely, a 10% decrease in the oil and natural gas index prices below the June 30, 2021 prices would result in a net liability of approximately $39 million. For additional information about derivative activity, see Note 3, Derivatives, in the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this report.

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. Additionally, we cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flows could be negatively impacted.

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, 2021.

There were no changes in the Company’s internal control over financial reporting during the second quarter of 2021 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

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers, including our Board Chair and Chief Executive Officer Trem Smith and Chief Financial Officer and Board member Cary Baetz (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act of 1934, on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company’s initial public offering (“IPO”); or (ii) Berry Corp.'s securities between July 26, 2018 and November 3, 2020 (the “Class Period”). In particular, the complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company’s business, operational efficiency and stability, and compliance policies, that artificially inflated the Company’s stock price, resulting in injury to the purported class members when the value of Berry Corp.’s common stock declined following release of its financial results for the third quarter of 2020 on November 3, 2020. The complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys’ fees and costs.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Other Matters.

For additional information regarding legal proceedings, see Note 4 to the condensed consolidated financial statements in Part I of this Form 10-Q and Note 5 to our consolidated financial statements for the year ended December 31, 2020 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 most recent Annual Report.

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

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 at the time, they authorized repurchases of up to $50 million under the program. The Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in 2018 and 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. 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 Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. We have not repurchased any shares under the stock repurchase program since 2019.

Item 6. Exhibits

Exhibit Number	Description
3.1	Second Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 of Form 8-K filed February 19, 2020)
3.2	Third Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.2 of Form 8-K filed February 19, 2020)
3.3	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))
3.4	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*	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

(*) Filed herewith.

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:

"*Absolute TSR*" means absolute total stockholder return.

"*AROs*" means asset retirement obligations.

"*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 and infrequent items.

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

"*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 and infrequent 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 for the U.S. Bureau of Land Management.

"b*oe*" 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.

"b*oe/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.

"*CAA*" is an abbreviation for the Clean Air Act, which governs air emissions.

"*CalGEM*" is an abbreviation for the California Geologic Energy Management Division.

"*Cap-and-trade*" is a statewide program in California established by the Global Warming Solutions Act of 2006 which outlined an enforceable compliance obligation beginning with 2013 GHG emissions and currently extended through 2030.

“*CARB*” is an abbreviation for the California Air Resources Board.

“*CCA*” or “*CCAs*” is an abbreviation for California carbon allowances.

“*CERCLA*” is an abbreviation for the Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous substances have been released into the environment (commonly known as “*Superfund*”).

“*Clean Water Rule*” refers to the rule issued in August 2015 by the EPA and U.S. Army Corps of Engineers which expanded the scope of the federal jurisdiction over wetlands and other types of waters.

“*COGCC*” is an abbreviation for the Colorado Oil and Gas Conservation Commission.

“*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.

“*CPUC*” is an abbreviation for the California Public Utilities Commission.

“*CWA*” is an abbreviation for the Clean Water Act, which governs discharges to and excavations within the waters of the United States.

“*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.

“*EH&S*” is an abbreviation for Environmental, Health & Safety.

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

“*EOR*” means enhanced oil recovery.

“*EPA*” is an abbreviation for the United States Environmental Protection Agency.

“*EPS*” is an abbreviation for earnings per share.

“*ESA*” is an abbreviation for the federal Endangered Species Act.

“*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.

“*FASB*” is an abbreviation for the Financial Accounting Standards Board.

“*FERC*” is an abbreviation for the Federal Energy Regulatory Commission.

"*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.

"*FIP*" is an abbreviation for Federal Implementation Plan.

"*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.

"*GAAP*" is an abbreviation for U.S. generally accepted accounting principles.

"*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.

"*GHG*" or "*GHGs*" is an abbreviation for greenhouse gases.

"*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.

"*IPO*" is an abbreviation for initial public offering.

"*LCFS*" is an abbreviation for low carbon fuel standard.

"*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.

"*Levered Free Cash Flow*" is a non-GAAP financial measure defined as Adjusted EBITDA less interest expense, dividends and capital expenditures.

"*LIBOR*" is an abbreviation for London Interbank Offered Rate.

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

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

"*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.

"*mm*bb*l*" means one million barrels of oil, condensate or NGLs.

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

"*mmbtu*" means one million btus.

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

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

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

"*MTBA*" is an abbreviation for Migratory Bird Treaty Act.

"*MW*" means megawatt.

"*MWHs*"means megawatt hours.

"*NAAQS*" is an abbreviation for the National Ambient Air Quality Standard.

"*NASDAQ*" means Nasdaq Global Select Market.

"*NEPA*" is an abbreviation for the National Environmental Policy Act, which requires careful evaluation of the environmental impacts of oil and natural gas production activities on federal lands.

"*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.

"*NGA*" is an abbreviation for the Natural Gas Act.

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

"*NRI*" is an abbreviation for net revenue interest.

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

"*OPEC*" is an abbreviation for the Organization of the Petroleum Exporting Countries.

"*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.

"*OSHA*" is an abbreviation for the Occupational Safety and Health Act of 1970.

"*OTC*" means over-the-counter

"*PALs*" is an abbreviation for project approval letters.

"*PCAOB*" is an abbreviation for the Public Company Accounting Oversight Board.

"*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.

"*PHMSA*" is an abbreviation for the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

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

"*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.

"*PSUs*" means performance-based restricted stock units

"*PURPA*" is an abbreviation for the Public Utility Regulatory Policies Act.

"*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.

"*QF*" means qualifying facility.

"*RCRA*" is an abbreviation for the Resource Conservation and Recovery Act, which governs the management of solid waste.

"*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.

"*Relative TSR*" means relative total stockholder return.

"*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.

"*RSUs*" is an abbreviation for restricted stock units.

"SARs" is an abbreviation for stock appreciation rights.

"*SDWA*" is an abbreviation for the Safe Drinking Water Act, which governs the underground injection and disposal of wastewater;.

"*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.

"*SPCC plans*" means spill prevention, control and countermeasure plans.

"*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.

"*Stimulating*" 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.

"*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.

"*Superfund*" is a commonly known term for CERLA.

"*UIC*" is an abbreviation for the Underground Injection Control program.

"*Unconventional resource plays*" means a resource play that uses methods other than traditional vertical well extraction. Unconventional resources are trapped in reservoirs with low permeability, meaning little to no ability for the oil or natural gas to flow through the rock and into a wellbore. Examples of unconventional oil resources include oil shales, oil sands, extra-heavy oil, gas-to-liquids and coal-to-liquids.

"*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.

"*WST*" is an abbreviation for well stimulation treatment.

"*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 Corporation (bry) (Registrant)
Date:	August 4, 2021	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	August 4, 2021	*/s/* M. S. Helm
		Michael S. Helm Chief Accounting Officer (Principal Accounting Officer)

EXHIBIT 31.1

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, A. T. “Trem” Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Berry Corporation (bry) (the “registrant”);

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

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

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

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

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

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

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

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

   (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 4, 2021

/s/ A. T. Smith

A. T. “Trem” Smith
President and Chief Executive Officer

EXHIBIT 31.2

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cary Baetz, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Berry Corporation (bry) (the “registrant”);

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

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

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

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

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

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

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

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

   (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 4, 2021

/s/ Cary Baetz

Cary Baetz
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

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

In connection with the quarterly report on Form 10-Q of Berry Corporation (bry) (the "Company") for the fiscal period ended June 30, 2021, as filed with the Securities and Exchange Commission on August 4, 2021 (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, to the best of our knowledge that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; 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 4, 2021

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

Date: August 4, 2021

/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 Corporation (bry) and will be retained by Berry Corporation (bry) and furnished to the Securities and Exchange Commission or its staff upon request.

This 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.