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 March 31, 2024

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 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an 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 April 30, 2024 76,938,994

Table of Contents

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)

	March 31, 2024	December 31, 2023
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,457	$ 4,835
Accounts receivable, net of allowance for doubtful accounts of $655 at March 31, 2024 and December 31, 2023	89,937	86,918
Derivative instruments	—	5,288
Other current assets	45,979	43,759
Total current assets	139,373	140,800
Noncurrent assets:		
Oil and natural gas properties	1,921,843	1,906,134
Accumulated depletion and amortization	(627,966)	(592,621)
Total oil and natural gas properties, net	1,293,877	1,313,513
Other property and equipment	169,799	167,767
Accumulated depreciation	(78,972)	(74,668)
Total other property and equipment, net	90,827	93,099
Deferred income taxes	41,455	30,308
Derivative instruments	—	5,463
Other noncurrent assets	9,984	10,975
Total assets	$ 1,575,516	$ 1,594,158
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 184,539	$ 213,401
Derivative instruments	45,908	9,781
Total current liabilities	230,447	223,182
Noncurrent liabilities:		
Long-term debt	448,121	427,993
Derivative instruments	20,667	959
Deferred income taxes	—	2,344
Asset retirement obligations	177,900	176,578
Other noncurrent liabilities	9,537	5,126
Commitments and Contingencies - Note 4		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 88,942,805 and 87,671,241 shares issued; and 76,938,994 and 75,667,430 shares outstanding, at March 31, 2024 and December 31, 2023, respectively)	89	88
Additional paid-in-capital	790,108	819,157
Treasury stock, at cost (12,003,811 shares at March 31, 2024 and December 31, 2023, respectively)	(113,768)	(113,768)
Retained earnings	12,415	52,499
Total stockholders' equity	688,844	757,976
Total liabilities and stockholders' equity	$ 1,575,516	$ 1,594,158

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 March 31,	
	2024	2023
	(in thousands, except per share amounts)	
Revenues and other:		
Oil, natural gas and natural gas liquids sales	$ 166,318	$ 166,357
Services revenue	31,683	44,623
Electricity sales	4,243	5,445
(Losses) gains on oil and gas sales derivatives	(71,200)	38,499
Other revenues	67	45
Total revenues and other	131,111	254,969
Expenses and other:		
Lease operating expenses	60,697	134,835
Costs of services	27,304	36,099
Electricity generation expenses	1,093	2,500
Transportation expenses	1,059	1,041
Acquisition costs	2,617	—
General and administrative expenses	20,234	31,669
Depreciation, depletion, and amortization	42,831	40,121
Taxes, other than income taxes	15,689	10,460
Losses (gains) on natural gas purchase derivatives	4,481	(610)
Other operating (income)	(133)	(286)
Total expenses and other	175,872	255,829
Other expenses:		
Interest expense	(9,140)	(7,837)
Other, net	(83)	(75)
Total other expenses	(9,223)	(7,912)
Loss before income taxes	(53,984)	(8,772)
Income tax (benefit)	(13,900)	(2,913)
Net loss	$ (40,084)	$ (5,859)
Net loss per share:		
Basic	$ (0.53)	$ (0.08)
Diluted	$ (0.53)	$ (0.08)

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

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

	Three-Month Period Ended March 31, 2023				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	(in thousands)				
December 31, 2022	$ 86	$ 821,443	$ (103,739)	$ 82,695	$ 800,485
Shares withheld for payment of taxes on equity awards and other	—	(4,260)	—	—	(4,260)
Stock-based compensation	—	4,989	—	—	4,989
Issuance of common stock	2	—	—	—	2
Dividends declared on common stock, $0.50/share	—	—	—	(42,421)	(42,421)
Net loss	—	—	—	(5,859)	(5,859)
March 31, 2023	$ 88	$ 822,172	$ (103,739)	$ 34,415	$ 752,936

	Three-Month Period Ended March 31, 2024				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	(in thousands)				
December 31, 2023	$ 88	$ 819,157	$ (113,768)	$ 52,499	$ 757,976
Shares withheld for payment of taxes on equity awards and other	—	(5,257)	—	—	(5,257)
Stock-based compensation	—	616	—	—	616
Issuance of common stock	1	—	—	—	1
Dividends declared on common stock, $0.26/share	—	(24,408)	—	—	(24,408)
Net loss	—	—	—	(40,084)	(40,084)
March 31, 2024	$ 89	$ 790,108	$ (113,768)	$ 12,415	$ 688,844

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

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

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (40,084)	$ (5,859)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	42,831	40,121
Amortization of debt issuance costs	682	636
Stock-based compensation expense	385	4,766
Deferred income taxes	(13,491)	(2,913)
Other operating expenses	113	604
Derivative activities:		
Total losses (gains)	75,681	(39,109)
Cash settlements (paid) received on derivatives	(9,094)	47,467
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(3,006)	18,615
(Increase) in other assets	(1,746)	(383)
(Decrease) in accounts payable and accrued expenses	(27,341)	(57,933)
Increase (decrease) in other liabilities	2,343	(4,231)
Net cash provided by operating activities	27,273	1,781
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(16,936)	(20,633)
Changes in capital expenditures accruals	(957)	(6,170)
Acquisitions, net of cash received	(768)	(3,657)
Net cash used in investing activities	(18,661)	(30,460)
Cash flows from financing activities:		
Borrowings under 2021 RBL credit facility	175,500	53,000
Repayments on 2021 RBL credit facility	(155,500)	(12,000)
Dividends paid on common stock	(24,407)	(40,194)
Shares withheld for payment of taxes on equity awards and other	(5,257)	(4,260)
Debt issuance cost	(326)	—
Net cash used in financing activities	(9,990)	(3,454)
Net (decrease) in cash and cash equivalents	(1,378)	(32,133)
Cash and cash equivalents:		
Beginning	4,835	46,250
Ending	$ 3,457	$ 14,117

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

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

Note 1—Basis of Presentation

"Berry Corp." refers to Berry Corporation (bry), a Delaware corporation, which is the sole member of each of its Delaware limited liability company subsidiaries: (1) Berry Petroleum Company, LLC ("Berry LLC"), which owns Macpherson Energy, LLC ("Macpherson Energy") and its subsidiaries; (2) CJ Berry Well Services Management, LLC ("C&J Management") and (3) C&J Well Services, LLC, ("C&J," together with C&J Management, "CJWS"). As the context may require, the "Company," "we," "our" or similar words in this report refer to, as the context may require, Berry Corp., together with its subsidiaries, Berry LLC, C&J Management, and C&J.

Nature of Business

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived oil and gas reserves. We operate in two business segments: (i) exploration and production ("E&P") and (ii) well servicing and abandonment. Our E&P assets are located in California and Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (60% oil and 40% gas). We operate our well servicing and abandonment segment in California.

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 E&P 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. Securities 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, 2023.

New Accounting Standards Issued, But Not Yet Adopted

In November 2023, the Financial Accounting Standards Board ("FASB") issued guidance to improve the reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. In addition, the guidance enhances interim disclosure requirements, clarifies circumstances in which an entity can disclose multiple segment measures of profit or loss and contains other disclosure requirements. The purpose of the guidance is to enable investors to better understand an entity's overall performance and assess potential future cash flows. The guidance is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. We are currently evaluating the impact the new guidance will have on our consolidated financial statements.

In December 2023, the FASB issued rules to enhance the annual income tax disclosure to address investors' request for more information regarding tax risks and opportunities present in an entity's operations related to the effective tax rate reconciliation and income taxes paid. The guidance is effective for fiscal periods beginning after December 15, 2024, with early adoption permitted for annual financial statements. We are currently evaluating the impact the new guidance will have on our consolidated financial statements.

Note 2—Debt

The following table summarizes our outstanding debt:

	March 31, 2024	December 31, 2023	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ 51,000	$ 31,000	variable rates 10.75% (2024) and 10.50% (2023)	August 26, 2025	Mortgage on 90% of Present Value of proven oil and gas reserves and lien on certain other assets
2022 ABL Facility	—	—	variable rates 9.75% (2024) and 9.75% (2023)	June 5, 2025	CJWS property and certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	451,000	431,000			
Less: Debt Issuance Costs	(2,879)	(3,007)			
Long-Term Debt, net	$ 448,121	$ 427,993			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At March 31, 2024 and December 31, 2023, debt issuance costs reported in "other noncurrent assets" on the balance sheet were approximately (i) $2 million and $3 million, respectively, net of amortization, for the Credit Agreement, dated as of August 26, 2021, among Berry Corp, as a guarantor, Berry LLC, as the borrower, JPMorgan Chase Bank, N.A., as the administrative agent and an issuing bank, and each of the lenders from time to time party thereto (as amended, restated, modified or otherwise supplemented from time to time, the "2021 RBL Facility") and (ii) an immaterial amount, net of amortization, for the Revolving Loan and Security Agreement, dated as of August 9, 2022, among C&J and C&J Management, as borrowers, and Tri Counties Bank, as lender (as amended, restated, supplemented or otherwise modified from time to time, the "2022 ABL Facility"). At March 31, 2024 and December 31, 2023, 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 $3 million, respectively.

For each of the three month periods ended March 31, 2024 and 2023, the amortization expense for the 2021 RBL Facility, the 2022 ABL Facility and the 2026 Notes, combined, was approximately $1 million. The amortization of debt issuance costs is presented in "interest expense" on the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amounts of the 2021 RBL Facility and the 2022 ABL Facility approximate fair value because the interest rates are variable and reflect market rates. The 2021 RBL Facility and 2022 ABL Facility are Level 2 in the fair value hierarchy. The fair value of the 2026 Notes was approximately $396 million and $391 million at March 31, 2024 and December 31, 2023, respectively. The 2026 Notes are Level 1 in the fair value hierarchy.

2021 RBL Facility

The 2021 RBL Facility provides for a revolving loan with up to $ 500 million of commitment, subject to a reserve borrowing base and an aggregate elected commitment amount. The borrowing base under the 2021 RBL Facility is redetermined semi-annually, and the borrowing base redeterminations generally become effective each May and November, although the borrower and the lenders may each make one interim redetermination between scheduled redeterminations.

As of March 31, 2024, the 2021 RBL Facility had a $ 500 million revolving commitment, a $200 million borrowing base, a $200 million aggregate elected commitment amount and a $20 million sublimit for the issuance of letters of credit (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). Availability under the 2021 RBL Facility may not exceed the lesser of the aggregate elected commitment amount or the borrowing base less outstanding advances and letters of credit. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the terms of the 2021 RBL Facility. The 2021 RBL Facility is available to us for general corporate purposes, including working capital.

The outstanding borrowings under the 2021 RBL Facility bear interest at a rate equal to, at our option, either (a) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% or (b) a term SOFR reference rate, plus an applicable margin ranging from 3.0% to 4.0%, in each case determined based on the utilization level under the 2021 RBL Facility. Interest on base rate borrowings is payable quarterly in arrears and interest on term SOFR borrowings accrues in respect of interest periods of one, three or six months, at the election of the borrower, and is payable on the last day of such interest period (or, for interest periods of six months, three months after the commencement of such interest period and at the end of such interest period). Unused commitment fees are charged at a rate of 0.50%.

The 2021 RBL Facility 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. In addition, the 2021 RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a leverage ratio of not more than 2.75 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of March 31, 2024, we were in compliance with all of covenants under the 2021 RBL Facility.

The 2021 RBL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If we do not comply with the financial and other covenants in the 2021 RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2021 RBL Facility and terminate the commitments thereunder.

The 2021 RBL Facility is guaranteed by Berry Corp. and certain of its subsidiaries. Each future subsidiary of Berry Corp., with certain exceptions, is required to guarantee our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements. The lenders under the 2021 RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions.

As of March 31, 2024, we had $51 million borrowings outstanding, $10 million in letters of credit outstanding and approximately $139 million of available borrowing capacity under the 2021 RBL Facility.

2022 ABL Facility

Subject to satisfaction of customary conditions precedent to borrowing, as of March 31, 2024, C&J and C&J Management could borrow up to the lesser of (x) $10 million and (y) the borrowing base under the 2022 ABL Facility, with a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $7.5 million (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). The “borrowing base” is an amount equal to 80% of the balance due on eligible accounts receivable, subject to reserves that the lender may implement in its reasonable discretion. As of March 31, 2024, the borrowing base was $10 million. Interest on the outstanding principal amount of the revolving loans under the 2022 ABL Facility accrues at a per annum rate equal to 1.25% the variable rate of interest, on a per annum basis, which is announced and/or published in the “Money Rates” section of The Wall Street Journal from time to time as its “Prime Rate”. Interest is due quarterly, in arrears. The 2022 ABL Facility matures on June 5, 2025, unless terminated in accordance with the terms of the 2022 ABL Facility.

The 2022 ABL Facility requires C&J and C&J Management to comply with the following financial covenants (i) maintain on a consolidated basis a ratio of total liabilities to tangible net worth of no greater than 1.5 to 1.0 at any time; (ii) reduce the amount of revolving advances outstanding under the 2022 ABL Facility to not more than 90% of the lesser of (a) the maximum revolving advance amount or (b) the borrowing base, as of the lender’s close of business on the last day of each fiscal quarter; and (iii) maintain net income before taxes of not less than $1.00 as of each fiscal year end. As of March 31, 2024, each of C&J and C&J Management was in compliance with all of the covenants under the 2022 ABL Facility.

The 2022 ABL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If C&J or C&J Management does not comply with the financial and other covenants in the 2022 ABL Facility, the lender may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2022 ABL Facility and terminate the commitment thereunder. The obligations of C&J and C&J Management under the 2022 ABL Facility are not guaranteed by Berry Corp. or Berry LLC and Berry Corp. and Berry LLC do not and are not required to provide any credit support for such obligations.

As of March 31, 2024, each of C&J and C&J Management had no borrowings and $3 million letters of credit outstanding with $7 million of available borrowing capacity under the 2022 ABL Facility.

Senior Unsecured Notes

In February 2018, Berry LLC completed a private issuance of $400 million in aggregate principal amount of 7.0% senior unsecured notes due February 2026, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount.

The 2026 Notes are Berry LLC’s senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The 2026 Notes are fully and unconditionally guaranteed on a senior unsecured basis by Berry Corp and certain of its subsidiaries. C&J and C&J Management do not guarantee the 2026 Notes. Macpherson Energy and certain of its subsidiaries became guarantors of the 2026 Notes on January 4, 2024 and February 8, 2024 pursuant to supplemental indentures.

The indenture governing the 2026 Notes contains customary covenants and events of default (in some cases, subject to grace periods). We were in compliance with all covenants under the 2026 Notes as of March 31, 2024.

Debt Repurchase Program

In February 2020, the board of directors (the “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 do not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any notes under this program.

Note 3—Derivatives

We utilize derivatives, such as swaps, puts, calls and collars, 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. In addition to satisfying the oil hedging requirements of the 2021 RBL Facility, which specifies the volume and types of our hedges, 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 fixed dividends as applicable, with the oil and gas sales hedges for a period of up to three 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 three years. We have also entered into gas transportation contracts to help reduce the price fluctuation exposure, however these do not qualify as hedges. 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. We had no such transactions in the periods presented.

Oil Sales Hedges

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

For our sold call options, we would make settlement payments for prices above the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices below the indicated weighted-average price per barrel, other than any applicable deferred premium.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices above the indicated weighted-average price per barrel, other than any applicable deferred premium.

For our sold puts, we would make settlement payments for prices below the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices above the indicated weighted-average price per barrel, other than any applicable deferred premium.

Gas Purchase Hedges

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

For some of our options we paid or received a premium at the time the positions were created and for others, the premium payment or receipt is deferred until the time of settlement. As of March 31, 2024, we have net payable deferred premiums of approximately $1 million, which is reflected in the mark-to-market valuation and will be payable through December 31, 2024.

We use oil and gas production hedges to protect our sales against decreases in oil and gas prices. We also use natural gas purchase hedges 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 March 31, 2024, we had the following crude oil production and gas purchases hedges.

	Q2 2024	Q3 2024	Q4 2024	FY 2025	FY 2026	FY 2027
Brent - Crude Oil production						
Swaps						
Hedged volume (bbls)	1,611,294	1,481,749	1,438,656	2,669,125	2,039,268	540,000
Weighted-average price ($/bbl)	$ 78.97	$ 76.88	$ 76.93	$ 75.23	$ 71.11	$ 71.42
Sold Calls[(1)]						
Hedged volume (bbls)	91,000	92,000	92,000	2,486,127	1,251,500	—
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 105.00	$ 91.11	$ 85.53	$ —
Purchased Puts (net)[(2)]						
Hedged volume (bbls)	318,500	322,000	322,000	365,000	—	—
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ —	$ —
Purchased Puts (net)[(2)]						
Hedged volume (bbls)	—	—	—	2,121,127	1,251,500	—
Weighted-average price ($/bbl)	$ —	$ —	$ —	$ 60.00	$ 60.00	$ —
Sold Puts (net)[(2)]						
Hedged volume (bbls)	45,500	46,000	46,000	—	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ 40.00	$ —	$ —	$ —
NWPL - Natural Gas purchases[(3)]						
Swaps						
Hedged volume (mmbtu)	3,640,000	3,680,000	3,680,000	6,080,000	—	—
Weighted-average price ($/mmbtu)	$ 3.96	$ 3.96	$ 3.96	$ 4.27	$ —	$ —

____

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.

(2) Purchased puts and sold puts with the same strike price have been presented on a net basis.

(3) The term “NWPL” is defined as Northwest Rocky Mountain Pipeline.

In April 2024, we converted most of our calendar year 2025 Brent collar position to sold swaps, (Brent) 6,000 bbl/d at $77.11 for calendar 2025. The conversions included purchased puts/sold calls, (Brent): 4,000 bbl/d at $60.00/$90.00, 1,000 bbl/d at $50.00/$98.50, and 1,000 bbl/d at $60.00/$90.10.

In April 2024, we also added natural gas purchase swaps (NWPL) of 20,000 mmbtu/d at $4.28 beginning January 2025 through December 2025 and 10,000 mmbtu/d at $4.26 beginning January 2026 through October 2026.

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 March 31, 2024 and December 31, 2023:

	March 31, 2024			
	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	$ 9,151	$ (9,151)	$ —
Commodity Contracts	Non-current assets	10,296	(10,296)	—
Liabilities:				
Commodity Contracts	Current liabilities	(55,059)	9,151	(45,908)
Commodity Contracts	Non-current liabilities	(30,963)	10,296	(20,667)
Total derivatives		$ (66,575)	$ —	$ (66,575)

	December 31, 2023			
	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	$ 26,230	$ (20,942)	$ 5,288
Commodity Contracts	Non-current assets	28,992	(23,529)	5,463
Liabilities:				
Commodity Contracts	Current liabilities	(30,723)	20,942	(9,781)
Commodity Contracts	Non-current liabilities	(24,488)	23,529	(959)
Total derivatives		$ 11	$ —	$ 11

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 2021 RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates, or with a non-lender counterparty that does not have an A or A2 credit rating or better from Standard & 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.

(Losses) gains on Derivatives

	Three Months Ended March 31,	
	2024	2023
	(in thousands)	
Realized (losses) gains on commodity derivatives:		
Realized (losses) on oil sales derivatives	$ (4,682)	$ (7,438)
Realized (losses) gains on natural gas purchase derivatives	(4,412)	54,905
Total realized (losses) gains on derivatives	$ (9,094)	$ 47,467
Unrealized (losses) gains on commodity derivatives:		
Unrealized (losses) gains on oil sales derivatives	$ (66,518)	$ 45,937
Unrealized (losses) on natural gas purchase derivatives	(69)	(54,295)
Total unrealized (losses) on derivatives	$ (66,587)	$ (8,358)
Total (losses) gains on derivatives	$ (75,681)	$ 39,109

Note 4—Commitments and Contingencies

In the normal course of business, we, or our subsidiaries, 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 any reserve balances at March 31, 2024 and December 31, 2023. 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 subsidiaries, 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 March 31, 2024, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Securities Class Action”) 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 (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the “Securities Act”), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the “Exchange Act”), 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 2018 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.

On November 1, 2021, the court-appointed co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company’s permits and permitting processes. The amended 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. The Defendants filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement at the hearing on February 6, 2024. On February 16, 2024, the Court entered a final settlement-approval order and judgment and terminated the case, and the settlement funds were subsequently disbursed to the class from an existing escrow account. The Defendants continue to maintain that the claims are without merit and admitted no liability in connection with the settlement. This litigation is now concluded,and the Company will no longer report on it in future filings.

On October 20, 2022, a shareholder derivative lawsuit (the “Assad Lawsuit”) was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties’ joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the “Karp Lawsuit,” together with the Assad Lawsuit, the “Shareholder Derivative Actions”) was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry’s 2022 proxy statement was false and misleading in that it suggested the Company’s internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties’ joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

Note 5—Equity

Cash Dividends

In the first quarter of 2024, our Board of Directors declared a quarterly fixed cash dividend totaling $ 0.12 per share, as well as a variable cash dividend of $0.14 per share which was based on the results of the fourth quarter of 2023, for a total of $ 0.26 per share, which we paid in March 2024. In April 2024, The Board of Directors approved a fixed cash dividend totaling $0.12 per share, which is expected to be paid in May 2024.

The Company anticipates that it will continue to pay quarterly cash dividends in the future. However, the payment and amount of future dividends remain within the discretion of the Board of Directors and will depend upon the Company’s future earnings, financial condition, capital requirements, and other factors.

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended March 31, 2024. As of March 31, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $ 114 million in aggregate. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of March 31, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $ 190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and the share repurchase program does not obligate the Company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Stock-Based Compensation

In March 2024, pursuant to the Company's 2022 Omnibus Incentive Plan, the Company granted (i) approximately 1,328,000 restricted stock units ("RSUs"), which will vest annually in equal amounts over three years or, in the case of directors, on March 1, 2025, and (ii) a target number of approximately 406,000 performance-based restricted stock units ("PSUs"), which will cliff vest at the end of a three-year performance period, at the earned performance level. The fair value of these RSU and PSU awards was approximately $13 million.

The RSUs awarded in March 2024 are solely time-based awards. Of the PSUs awarded in March 2024, (a) 50% of such will vest, at the earned performance level, based on the Company's absolute total stockholder return ("TSR") performance metric, which is defined as the capital gains per share of stock plus cumulative dividends and (b) 50% of such will vest, at the earned performance level, based on the relative TSR performance metric, which is defined as the capital gains per share of stock plus cumulative dividends, with TSR measured on a relative basis to the TSR of the 47 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. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient earns at the end of the performance period may range from 0% to 200% of the target number of PSUs granted.

The fair value of the RSUs was determined using the grant date stock price. The grant date fair value of the PSUs was determined using a Monte Carlo simulation to estimate the TSR ranking of the Company for the relative TSR award and the value of the absolute TSR award. The historical volatility was determined at the date of grant for the Company and for each company in the peer group. 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 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:

	March 31, 2024	December 31, 2023
	(in thousands)	
Prepaid expenses	$ 13,557	$ 12,330
Materials and supplies	18,460	17,021
Deposits	8,331	9,012
Oil inventories	3,756	4,098
Other	1,875	1,298
Total other current assets	$ 45,979	$ 43,759

Noncurrent assets

Other noncurrent assets at March 31, 2024 was approximately $ 10 million, which included $7 million of operating lease right-of-use assets, net of amortization and $2 million of deferred financing costs, net of amortization. At December 31, 2023, other non-current assets was approximately $ 11 million, which included $8 million of operating lease right-of-use assets, net of amortization and $ 3 million of deferred financing costs, net of amortization.

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

	March 31, 2024	December 31, 2023
	(in thousands)	
Accounts payable-trade	$ 26,239	$ 31,184
Deferred acquisition payable[(1)]	19,500	18,999
Accrued expenses	45,540	55,663
Royalties payable	16,849	28,179
Greenhouse gas liability - current portion	37,694	37,945
Taxes other than income tax liability	11,038	6,488
Accrued interest	4,895	11,999
Asset retirement obligations - current portion	20,000	20,000
Operating lease liability	2,784	2,944
Total accounts payable and accrued expenses	$ 184,539	$ 213,401

(1) Relates to the remaining payable of $20 million, on a discounted basis, for the acquisition of Macpherson Energy, due in July 2024.

Noncurrent liabilities

The increase of approximately $1 million in the long-term portion of the asset retirement obligations from $ 177 million at December 31, 2023 to $ 178 million at March 31, 2024 was due to $3 million of accretion expense, largely offset by $ 2 million of liabilities settled during the period.

Other noncurrent liabilities at March 31, 2024 was approximately $ 10 million, which included approximately $5 million of greenhouse gas liability, and $5 million of operating lease noncurrent liability. At December 31, 2023, other noncurrent liabilities was approximately $ 5 million, which was noncurrent operating lease liability.

Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2024	2023
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Deferred consideration payable for acquisition	$ 19,500	$ —
Material inventory transfers to oil and natural gas properties	$ 781	$ 288
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 15,256	$ 14,388

Note 7—Acquisition and Divestiture

In April 2024, we purchased a 21% interest in four, two-to-three mile lateral wellbores that have been drilled and completed and are expected to be put on production in the second quarter of 2024. These are adjacent to our existing operations in Utah, and the results from these wells will be used to evaluate opportunities on our own acreage. The total purchase price was approximately $10 million, subject to customary purchase price adjustments.

Note 8—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 months ended March 31, 2024 and March 31, 2023, no RSU or PSU shares were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method.

	Three Months Ended March 31,	
	2024	2023
	(in thousands except per share amounts)	
Basic EPS calculation		
Net loss	$ (40,084)	$ (5,859)
Weighted-average shares of common stock outstanding	76,254	76,112
Basic loss per share	$ (0.53)	$ (0.08)
Diluted EPS calculation		
Net loss	$ (40,084)	$ (5,859)
Weighted-average shares of common stock outstanding	76,254	76,112
Dilutive effect of potentially dilutive securities[1]	—	—
Weighted-average common shares outstanding - diluted	76,254	76,112
Diluted loss per share	$ (0.53)	$ (0.08)

(1) We excluded approximately 1.1 million and 3.1 million of combined RSUs and PSUs from the dilutive weighted-average common shares outstanding for each of the three months ended March 31, 2024 and 2023 because their effect was anti-dilutive.

Note 9—Revenue Recognition

We derive revenue from sales of oil, natural gas and natural gas liquids (“NGL”), with additional revenue generated from sales of electricity. Revenue from CJWS is generated from well servicing and abandonment business.

The following table provides disaggregated revenue for the three months ended March 31, 2024 and 2023:

	Three Months Ended March 31,	
	2024	2023
	(in thousands)	
Oil sales	$ 162,752	$ 152,134
Natural gas sales	2,719	13,543
Natural gas liquids sales	847	680
Service revenue(1)	31,683	44,623
Electricity sales	4,243	5,445
Other revenues	67	45
Revenues from contracts with customers	202,311	216,470
(Losses) gains on oil and gas sales derivatives	(71,200)	38,499
Total revenues and other	$ 131,111	$ 254,969

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $35 million and $46 million, and after the intercompany elimination of $4 million and $2 million, net service revenue was approximately $32 million and approximately $45 million for the quarters ended March 31, 2024 and 2023, respectively.

Note 10—Segment Information

We operate in two business segments: (i) E&P and (ii) well servicing and abandonment. The E&P segment is engaged in the exploration and production of onshore, low geologic risk, long-lived oil and gas reserves located in California and Utah. The well servicing and abandonment segment is operated by CJWS and provides wellsite services in California to oil and natural gas production companies, with a focus on well servicing, well abandonment services and water logistics.

The well servicing and abandonment segment occasionally provides services to our E&P segment, as such, we recorded an intercompany elimination of $4 million in revenue and expense during consolidation for the three months ended March 31, 2024. The intercompany elimination was $ 2 million for the three months ended March 31, 2023.

The following table represents selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis.

	Three Months Ended March 31, 2024			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 170,628	$ 35,468	$ (3,785)	$ 202,311
Net (loss) income before income taxes	$ (24,836)	$ (1,269)	$ (27,879)	$ (53,984)
Capital expenditures	$ 15,417	$ 1,332	$ 187	$ 16,936
Total assets	$ 1,625,178	$ 65,948	$ (115,610)	$ 1,575,516

	Three Months Ended March 31, 2023			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 171,847	$ 46,363	$ (1,740)	$ 216,470
Net income (loss) before income taxes	$ 24,170	$ 2,114	$ (35,056)	$ (8,772)
Capital expenditures	$ 19,272	$ 982	$ 379	$ 20,633
Total assets	$ 1,471,679	$ 80,897	$ (12,335)	$ 1,540,241

(1) These revenues do not include hedge settlements.

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 (“MD&A”) should be read in conjunction with our interim unaudited consolidated financial statements and related notes presented in this Quarterly Report on Form 10-Q (the “Quarterly Report”), 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, 2023 (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, Berry Corp., together with its subsidiaries, Berry LLC, C&J Management, and C&J.

Our Company

We are a value-driven western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived oil and gas reserves. We operate in two business segments: (i) exploration and production (“E&P”) and (ii) well servicing and abandonment. Our E&P assets are located in California and Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (60% oil and 40% gas).

With respect to our E&P business in California, we focus on conventional, shallow oil reservoirs. The drilling and completion of such wells are relatively low-cost in contrast to unconventional resource plays. The California oil market is primarily tied to Brent-influenced pricing which has typically realized premium pricing relative to West Texas Intermediate (“WTI”). All of our California assets are located in oil-rich reservoirs in the San Joaquin basin, which has more than 150 years of production history and substantial oil remaining in place. As a result of the data generated over the basin’s long history of production, its reservoir characteristics and low geological risk opportunities are generally well understood.

We also have upstream assets in Utah, located in the Uinta basin, which produce oil and natural gas at depths ranging from 4,000 feet to 8,000 feet. We have high operational control of our existing acreage (99,000 net acres), which provides significant upside for additional development and recompletions.

In our well servicing and abandonment segment, we operate one of the largest upstream well servicing and abandonment businesses in California, which operates as C&J. C&J provides wellsite services in California to oil and natural gas production companies, including well servicing and water logistics. Additionally, C&J performs plugging and abandonment services on wells at the end of their productive life, which we believe creates a strategic growth opportunity for Berry based on the significant market of idle wells within California.

The core of our strategy is to create value by generating significant free cash flow in excess of our operating costs, while optimizing capital efficiency. In doing so, we seek to maximize enterprise value through overall returns. Since our initial public offering in July 2018 (“IPO”), we have demonstrated our commitment to maximizing enterprise value and returning free cash flow to shareholders through dividends and share repurchases. We have also made acquisitions that are accretive to cash flows.

Our shareholder return model is simple and demonstrates our commitment to optimize free cash flow allocation and long-term returns to our shareholders, including deleveraging through enhanced cash flows and debt reduction. As part of our strategy, we opportunistically consider bolt-on acquisitions, which contribute to our goal to maintain our existing production volumes (particularly in the current regulatory environment, when there are restrictions on the ability to obtain permits for new well drilling), and could even moderately grow production. Depending on size, bolt-on acquisitions may be funded in whole or in part from reallocation of capital expenditures, as a way of increasing Adjusted Free Cash Flow, a non-GAAP measure, and may utilize the 80% portion of Adjusted Free Cash

Flow specified in the shareholder return model.

We review the allocations under our shareholder return model from time to time based on industry conditions, operational results and other factors. In 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and capital expenditures. This update better aligns with the full capital expenditure requirements of the Company. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represented the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and was defined as capital expenditures, excluding, when applicable, (i) E&P capital expenditures related to strategic business expansion, such as acquisitions and divestitures of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes, (ii) capital expenditures in our well servicing and abandonment segment, (iii) corporate expenditures that are related to ancillary sustainability initiatives and/or (iv) other expenditures that are discretionary and unrelated to maintenance of our core business. Adjusted Free Cash Flow for prior periods has not been retroactively adjusted for the updated definition. Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, bolt-on acquisitions or other growth opportunities, or other discretionary expenditures, since we have non-discretionary expenditures that are not deducted from this measure. Adjusted Free Cash Flow is a non-GAAP financial measure. See "Non-GAAP Financial Measures" for a reconciliation of cash provided by operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted Free Cash Flow.

We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling, sidetrack and workover locations with attractive full-cycle economics will support our objectives to generate free cash flow, which funds our operations, optimizes capital efficiency and maximizes enterprise value. We also strive to maintain an appropriate liquidity position and manageable leverage profile that will enable us to explore attractive organic and strategic growth through commodity price cycles and acquisitions. In addition to operating and developing our existing assets efficiently and strategically, we seek to acquire accretive, producing bolt-on properties that complement our existing operations, enhance our cash flows and allow us to further our strategy of keeping production essentially flat year-over-year., subject to delays in the issuance of necessary permits and approvals. For more information, see Part I, Items 1 and 2. "Business and Properties—Regulatory Matters—Regulation of the Oil and Gas Industry" in our Annual Report. Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safer, more efficient and lower emission operations.

Recent Developments

In April 2024, we purchased a 21% interest in four, two-to-three mile lateral wellbores that have been drilled and completed and are expected to be put on production in the second quarter of 2024. These are adjacent to our existing operations in Utah, and the results from these wells will be used to evaluate opportunities on our own acreage. The total purchase price was approximately $10 million, subject to customary purchase price adjustments.

How We Plan and Evaluate Operations

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) Adjusted Free Cash Flow (c) production from our E&P business (d) E&P field operations measures; (e) HSE results; (f) general and administrative expenses; and (g) the performance of our well servicing and abandonment operations based on activity levels, pricing and relative performance for each service provided.

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of both our E&P business and CJWS. We also use Adjusted EBITDA in planning our capital expenditure allocation to sustain production levels and determining our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility (defined below in "—Liquidity and Capital Resources"). 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 unusual and infrequent items. See "Management's Discussion and Analysis—Non-GAAP Financial Measures" for a reconciliation of net income (loss) and net cash provided (used) by operating activities, our most directly comparable financial measures calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted EBITDA. This supplemental non-GAAP financial measure is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

Adjusted Free Cash Flow

We utilize our shareholder return model to determine the allocation of our Adjusted Free Cash Flow. This shareholder return model is simple and demonstrates our commitment to optimize free cash flow allocation and long-term returns to our shareholders, including deleveraging through enhanced cash flows and debt reduction. The allocations of Adjusted Free Cash Flow, last updated at the beginning of 2023, are intended to be (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. Any dividends (fixed or variable) actually paid will be determined by our Board of Directors in light of then existing conditions and circumstances, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors.

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.

E&P Field Operations

Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies, which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then sold to third parties. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

Health, Safety & Environmental

Like other companies in the oil and gas industry, the operations of both our E&P business and C&J are subject to complex federal, state and local laws and regulations that govern health and safety, the release or discharge of materials, and land use or environmental protection that may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Please see “—Regulatory Matters” in this Quarterly Report as well as Part I, Items 1 and 2. “Business and Properties—Regulatory Matters” and Part I, Item 1A. “Risk Factors” in our Annual Report for a discussion of the potential impact that government regulations, including those regarding HSE matters, may have upon our business, operations, capital expenditures, earnings and competitive position.

As part of our commitment to creating long-term 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 HSE performance through various measures, and we hold our employees and contractors to high standards. Meeting corporate HSE metrics, including with respect to HSE incidents 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. 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.

Well Servicing and Abandonment Operations Performance

We consistently monitor our well servicing and abandonment operations performance with revenue and cost by service and customer, as well as Adjusted EBITDA for this business.

Business Environment, Market Conditions and Outlook

Our operating and financial results, and those of the oil and gas industry as a whole, are heavily influenced by commodity prices, including differentials, which have and may continue to, fluctuate significantly as a result of numerous market-related variables, including global geopolitical and economic conditions, and local and regional market factors and dislocations. Oil and natural gas prices have been, and may remain, volatile. As a net gas purchaser, our operating costs are generally expected to be more impacted by the volatility of natural gas prices than our gas sales.

Our well servicing and abandonment business is dependent on expenditures of oil and gas companies, which can in part reflect the volatility of commodity prices, as well as the impact from changes in the regulatory environment. Because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by oil and gas companies for the maintenance of existing wells historically have been relatively stable and predictable when production is steady. Additionally, our customers' requirements to plug and abandon wells are largely driven by regulatory requirements that are less dependent on commodity prices.

In October 2022, OPEC+ announced initial reductions in production quotas that were extended through December 2023. In June 2023, OPEC+ further reduced production quotas from January 2024 through December 2024, which extended the October 2022 curtailment. In November 2023, OPEC+ announced additional voluntary cuts, for a combined total of 2.2 mmbbls/d, beginning January 2024 through March 2024. In March 2024, OPEC+ agreed to extend the 2.2 mmbbls/d cut into the second quarter of 2024.

Sanctions and import bans on Russian oil have been implemented by various countries in response to the ongoing conflict in Ukraine, further altering flows of global oil supply. Oil and natural gas prices could decrease or increase with any changes in demand due to, among other things, the ongoing conflict in Ukraine, the ongoing conflict in the Middle East, international sanctions, speculation as to future actions by OPEC+, higher gas prices, high interest rates, inflation and government efforts to reduce inflation, and possible changes in the overall health of the global economy, including increased volatility in financial and credit markets or a prolonged recession. Further, the volatility in oil and natural gas prices could accelerate a transition away from fossil fuels, resulting in reduced demand over the longer term. To what extent these and other external factors (such as government action with respect to climate change regulation) ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors, including future developments, that are not within our control and cannot be accurately predicted.

Additionally, like other companies in the oil and gas industry, our operations are subject to 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, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. See Part I, Items 1 and 2. "Business and Properties—Regulatory Matters—Regulation of Health, Safety and Environmental Matters" in our Annual Report for a description of laws and regulations that affect our business. For more information related to regulatory risks, see Part I, Item 1A. "Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

Commodity Pricing and Differentials

Our revenue, costs, profitability, shareholder returns 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 I, Item 1A. "Risk Factors" in our Annual Report.

Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. We use derivatives to hedge a portion of our forecasted oil and gas production and gas purchases to reduce our exposure to fluctuations in oil and natural gas prices. The following table sets forth certain average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the periods indicated below.

	Three Months Ended					
	March 31, 2024		December 31, 2023		March 31, 2023	
	Average Price	Realization[1]	Average Price	Realization[1]	Average Price	Realization[1]
Sales of Crude Oil (per bbl):						
Brent	$ 81.76		$ 82.85		$ 82.16	
Realized price without derivative settlements	$ 75.31	92%	$ 76.00	92%	$ 74.69	91%
Effects of derivative settlements	(2.17)		(3.35)		(3.65)	
Realized price with derivative settlements	$ 73.14	89%	$ 72.65	88%	$ 71.04	86%
WTI	$ 77.02		$ 78.49		$ 76.15	
Realized price without derivative settlements	$ 75.31	98%	$ 76.00	97%	$ 74.69	98%
Purchased Natural Gas (per mmbtu)						
Average Monthly Settled Price - NWPL	$ 3.41		$ 4.53		$ 22.36	
Realized price without derivative settlements	$ 3.99	117%	$ 5.29	117%	$ 20.74	93%
Effects of derivative settlements	0.92		0.44		(11.86)	
Realized price with derivative settlements	$ 4.91	144%	$ 5.73	126%	$ 8.88	40%

(1) Represents the percentage of our realized prices compared to the indicated index.

Oil Prices

California oil prices are Brent-influenced as California refiners import approximately 75% of the state's demand from OPEC+ countries and other waterborne sources. We believe that receiving Brent-influenced pricing contributes to our ability to continue realizing strong cash margins in California. Though the California market generally receives Brent-influenced pricing, California oil prices are also determined by local supply and demand dynamics, including third-party transportation and infrastructure capacity. In the fourth quarter of 2023, oil prices decreased relative to the third quarter of 2023. Prices were relatively flat in the first quarter in 2024 relative to the fourth quarter of 2023.

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 wells and recompletions. For the three months ended March 31, 2024, December 31, 2023, and March 31, 2023, Utah had an average realized oil price of $65.79, $67.20, and $63.27, respectively, compared to an average Brent oil price of $81.76, $82.85, and $82.16 for the same periods

Gas Prices

For our California steam operations, the price we pay for fuel gas purchases is generally based on the Northwest, Rocky Mountains index for the purchases made in the Rockies and the SoCal Gas city-gate index for the purchases made in California. We currently buy most of our gas in the Rockies. Now that we are purchasing a majority of our fuel gas in the Rockies, most of the purchases made in California use the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases was Kern, Delivered. The price from the Northwest, Rocky Mountain index was as high as $4.88 per mmbtu and as low as $1.78 per mmbtu in the first quarter of 2024. The price from the SoCal Gas city-gate index was as high as $5.37 per mmbtu and as low as $3.10 per mmbtu in the first quarter of 2024. Overall, on an unhedged basis, we paid an average of $3.99 per mmbtu in the first quarter of 2024 for our gas purchases. When including the hedging effects in our gas purchases, we paid $4.91, $5.73, and $8.88 per mmbtu in the first quarter of 2024, the fourth quarter of 2023, and the first quarter of 2023, respectively.

The price of our fuel gas sales is generally based on the Northwest, Rocky Mountains index, as selling at the same index as fuel gas purchases provides a natural hedge for gas purchases. In the first quarter of 2024, our Utah operations had an average realized gas price of $3.76, compared to an average Northwest, Rocky Mountains gas price of $3.41, which was a 110% realization. In the three months ended December 31, 2023 and March 31, 2023, Utah had an average realized gas price of $4.48, and $17.39, compared to an average Northwest, Rocky Mountains gas price of $4.53, or 99% realization, and $22.36, or 78% realization, respectively.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. Our key exposure to gas prices is in our costs. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. We purchase most of our gas in the Rockies and transport it to our California operations using our Kern River pipeline capacity. We buy approximately 48,000 mmbtu/d in the Rockies, and the remainder comes from California markets. The volume purchased in California fluctuates and averaged 5,000 mbbtu/d in the first quarter of 2024, 6,000 mmbtu/d in the fourth quarter of 2023, and 3,000 mmbtu/d in the first quarter of 2023. The natural gas we purchase in the Rockies is shipped to our operations in California to help limit our exposure to California fuel gas purchase price fluctuations. We strive to further minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of our gas purchases. 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. The Kern capacity allows us to purchase and sell natural gas at the same pricing indices.

We seek to mitigate a substantial portion of the gas purchase exposure for our cogeneration plants by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Aside from the impact gas prices have on electricity prices, these sales are generally higher in the summer months as they include seasonal capacity amounts. Gas prices declined in the first quarter of 2024 compared to the fourth quarter of 2023. The natural gas futures indicate that prices will rise toward the end of 2024 and into 2025.

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 two of our cogeneration facilities under long-term contracts with terms ending in December 2024 and November 2026. The most significant input and cost of the cogeneration facilities is natural gas.

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.

Regulatory Matters

Like other companies in the oil and gas industry, both our E&P business and CJWS are subject to complex and stringent federal, state, and local laws and regulations, and California, where most of our operations and assets are located, is one of the most heavily regulated states in the United States with respect to oil and gas operations. Collectively, the effect of the existing laws and regulations is to limit the number and location of our wells through restrictions on the use of our properties; limit our ability to develop certain assets and conduct certain operations, including through a restrictive and burdensome permitting and approval process; and have the effect of reducing the amount of oil and natural gas that we can produce from our wells, potentially reducing such production below levels that would otherwise be possible or economical. Additionally, the regulatory burden in the past has resulted, and in the future could result, in increased costs, and consequently has had an adverse effect on operations, capital expenditures, earnings and our competitive position, and may continue to have such effects in the future. Violations and liabilities with respect to these laws and regulations could also result in reputational damage and significant administrative, civil or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns, and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and future prospects. Our operations in California are particularly exposed to increased regulatory risks given the stringent environmental regulations imposed on the oil and gas industry, and current political and social trends in California continue to increase limitations on and impose additional permitting, mitigation and emissions control obligations, amongst others, upon the oil and gas industry. We cannot predict what new environmental laws or regulations California (or the federal government) may impose upon our operations in the future; however, any such future laws or regulations could materially and adversely impact our business and results of operations. For additional information about the potential impact that government regulations, including those regarding environmental matters, may have upon our business, operations, capital expenditures, earnings and competitive position, please see Part I, Item 1 “Regulatory Matters,” as well as Part I, Item 1A. “Risk Factors” in our Annual Report.

Over the last few years, a number of developments at both the California state and local levels have resulted in significant delays in the issuance of permits to drill new oil and gas wells in Kern County, where all of our California assets are located, as well as a more time and cost-intensive permitting process. The issuance of permits and other approvals for drilling and production activities by state and local agencies or by federal agencies are subject to environmental reviews under the California Environmental Quality Act (“CEQA”) and/or the National Environmental Policy Act (“NEPA”), respectively. The requirement to demonstrate compliance with CEQA and/or NEPA is currently resulting in (and in the future may result in) significant delays in the issuance of permits to drill new wells, as well as the potential imposition of mitigation measures and restrictions on proposed oil field operations, among other things. Before an operator can pursue drilling operations in California, they must first obtain permission to engage in oil and gas land use. CEQA requires the reviewing state and local agencies to consider the environmental impacts of the proposed oil and gas operations for permitting decisions. Historically, we satisfied CEQA by complying with the Kern County zoning ordinance for oil and gas operations, which was supported by the Kern County Environmental Impact Report (“EIR”). However, the EIR was legally challenged in 2020 and the use of the EIR is currently stayed and has been stayed through most of the litigation. On March 7, 2024 the California appellate court delivered an opinion finding certain deficiencies in the EIR and enjoining reliance on the EIR in connection with the issuance of oil and natural gas permit approvals until such deficiencies are remedied. Accordingly, our ability to rely on the EIR to demonstrate CEQA compliance to obtain permits and approvals to drill new wells is constrained unless and until Kern County is able to favorably resolve the litigation and certify a new revised EIR in compliance with CEQA. As a result of the litigation, since December 2022, neither we nor any other operator have received permits to drill new wells using the EIR to demonstrate CEQA compliance. In the meantime, to obtain permits for drilling new wells in Kern County we must demonstrate compliance with CEQA to CalGEM through means other than the EIR. Berry does have a separate environmental impact analysis covering certain assets, and we have historically received permits to drill new wells in the covered areas. However, we began to experience delays in the issuance of new drill permits in those areas during the third quarter of 2023, which we believe is due to changes in CalGEM’s CEQA review process. In fact, since January 2023, relatively few permits to drill new wells in California have been issued to any oil producer. Additionally, in the third quarter of 2023, we started to experience delays in the approval process for sidetrack and workover permits as well, which we believe is also due to changes in CalGEM's review process. Since that time, CalGEM has provided continued assurances that it is reviewing sidetrack and workover applications and working to finalize its approach to CEQA compliance with respect to such permit review that would allow the agency to ultimately return to regularly issuing these permits on a more predictable timeline. Nevertheless, CalGEM has only approved a relatively low number of sidetrack permits since November 2023 and we also continue to experience some delays in the approval process for workover permits. We currently have sufficient permits in hand that should allow us to maintain planned sidetrack drilling activity into July 2024 and conduct workover activity throughout the year. However, it is possible that such permit approval delays could continue throughout 2024, which would impede our ability to meet our planned 2024 sidetrack drilling program and/or limit our planned 2024 workover program. We are currently exploring a number of alternative permitting strategies to meet our 2024 drilling plan if the remaining sidetrack permits for our 2024 plan are not approved timely by CalGEM; however, we cannot guarantee that any of these strategies will ultimately be successful, and the inability to secure permits (on a timely basis or at all) could adversely impact our business and results of operations. See Part I, Item 1 and 2. "Business and Properties—Regulatory Matters—Regulation of the Oil and Gas Industry" in our Annual Report, as well as Part I, Item 1A. "Risk Factors" in our Annual Report for more information regarding the EIR and other permitting considerations.

On September 16, 2022, the California Governor signed into law Senate Bill No. 1137 (SB 1137) which prohibits CalGEM from permitting any new wells, or the rework of existing wells, if the proposed new drill or rework is within 3,200 feet of certain sensitive receptors such as homes, schools or parks. The bill would have become effective January 1, 2023. However, in December 2022, proponents of a voter referendum (the "Referendum") collected more than the required number of signatures to put Senate Bill No. 1137 on the November 2024 ballot. On February 3, 2023, the Secretary of State of California certified the signatures and confirmed that the Referendum qualifies for the November 2024 ballot. Accordingly, Senate Bill No. 1137 is stayed until it is put to a vote. Relatedly, a legislator introduced Senate Bill No. 556 (SB 556) into the California Senate in 2023, providing for joint and several liability for operators and owners of an entity that owns an oil and gas production facility for certain adverse health conditions within 3,200 feet of such facility, subject to limited defenses. Although this bill died during the last legislative session, an identical bill—Assembly Bill 3155 (AB 3155)—was introduced into the California Legislature in early 2024 and is currently under consideration. Separately, Assembly Bill 2716 (AB 2716) was introduced in 2024, which would require the plugging and abandonment of certain low-production wells located within 3,200 feet of a sensitive receptor within a certain timeframe or otherwise subjects operators to administrative penalties. We continue to monitor the progression of these bills, but we currently estimate that approximately 10% of our overall proved reserves as of December 31, 2023 are within the setbacks established by Senate Bill No. 1137. We do not expect this law to result in any material change in our overall existing proved developed producing reserves or current production rates.

Assembly Bill 1167 (AB 1167), signed into law by the California Governor in October 2023, imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in the state of California. AB 1167 requires such persons to fulfill bonding requirements in an amount determined by the state to sufficiently cover full plugging and abandonment costs, decommissioning, and site restoration of all wells and production facilities. Transfer of operatorship of a well or production facility is prohibited until the state has determined the appropriate bond amount and the bond has been filed. Upon signing AB 1167, the California Governor called for further legislative changes to the new requirements to mitigate against the potential risk of an increase in the number of orphaned wells becoming state liabilities following the implementation of the law. Similar to AB 1167, in early 2024, a California legislator introduced Assembly Bill 1866 (AB 1866) which would require the operator of any idle well to file, on or before July 1, 2025, a plan with the state to provide for the management and elimination of all idle wells, with consideration shown to a number of specified factors when prioritizing idle wells for testing or plugging and abandonment. Additionally, AB 1866 would require operators to restore the surface of the well pad to as near a natural state as practicable or to a condition suitable for alternative use. Any operator who fails to comply with AB 1866 would be subject to civil penalties.

In October 2023, the California Governor signed two bills that require quantitative and qualitative climate disclosures for certain public and private companies doing business in California. Senate Bill 253 (SB 253) requires the annual disclosure of Scope 1, 2 and 3 GHG emissions, with certain emissions data subject to third party assurance. The bill requires disclosure of Scope 1 and 2 GHG emissions beginning in 2026 for the 2025 reporting year and disclosure of Scope 3 GHG emissions beginning in 2027 for the 2026 reporting year. SB 253 is effective for public and private companies with total annual revenues exceeding $1 billion. Senate Bill 261 (SB 261) requires biennial disclosures posted on a company's website related to climate-related financial risks and the measures a company has adopted to reduce and adapt to such risks. The bill requires disclosure of the climate-related financial risk disclosures beginning in 2026 for the 2025 reporting year. SB 261 is effective for public and private companies with total annual revenues exceeding $500 million. Both SB 253 and 261 have been challenged in the U.S. District Court for the Central District of California.

Inflation

The U.S. inflation rate has become more significant in recent years. The Company, similar to other companies in our industry, has experienced inflationary pressures on our costs—namely inflationary pressures have resulted in increases to the costs of our goods, services and personnel, which in turn, have caused our capital expenditures and operating costs to rise. Such inflationary pressures have resulted from supply chain disruptions caused by the COVID-19 pandemic, increased demand, labor shortages and other factors, including the conflict between Russia and Ukraine. During 2024, inflation rates continued their trend of stabilizing as seen in the latter half of 2023. We are unable to accurately predict if such inflationary pressures and contributing factors will continue through 2024. However, as of March 31, 2024, we determined there have not been any material changes in inflationary pressures since the year ended December 31, 2023.

Seasonality

Seasonal weather conditions have in the past, and in the future likely will, impact our drilling, production and well servicing activities. Extreme weather conditions can pose challenges to meeting well-drilling and completion objectives and production goals. Seasonal weather can also lead to increased competition for equipment, supplies and personnel, which could lead to shortages and increased costs or delayed operations. Our operations have been, and in the future could be, impacted by ice and snow in the winter, especially in Utah, and by electrical storms and high temperatures in the spring and summer, as well as by wildfires and rain.

We seek to mitigate a substantial portion of the gas purchase exposure for our cogeneration plants by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Aside from the impact gas prices have on electricity prices, these sales are generally higher in the summer months as they include seasonal capacity amounts. In the first quarter of 2024, gas prices decreased from prices in the fourth quarter of 2023. Our hedging strategy coupled with our midstream access to gas from the Rockies helps us mitigate the impact of high natural gas prices on our cost structure.

Capital Expenditures

For the three months ended March 31, 2024, our total capital expenditures were approximately $17 million, including capitalized overhead and interest and excluding acquisitions and asset retirement spending. E&P and corporate expenditures were $16 million for the three months ended March 31, 2024 (excluding well servicing and abandonment capital of $1 million). Approximately 90% and 10% of these capital expenditures for the three months ended March 31, 2024 were directed to California and Utah operations, respectively.

Our 2024 capital expenditure budget for E&P operations, CJWS and corporate activities is between $95 to $110 million, which, if executed fully, we expect will result in 2024 production to be essentially flat compared with 2023. We currently anticipate oil production will be approximately 93% of total production volume in 2024, substantially consistent with 2023. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2024 capital development programs from cash flow from operations. Our current capital program for 2024 focuses on sidetracks and workovers. We also expect to benefit from a full year of production from the assets acquired from bolt-on acquisitions in the second half of 2023, which should help keep our production essentially flat in 2024 if we execute fully on our 2024 capital budget. As a result of ongoing regulatory uncertainty in California impacting the permitting process in Kern County where all of our California assets are located, the capital program has been prepared based on the assumption that we will not receive additional new drill permits in California in 2024, but that we will continue to timely receive the other permits and approvals needed for planned activities. However, as discussed elsewhere in this Quarterly Report, we are seeing delays in our ability to timely obtain workover and sidetrack permits, in addition to new drill permits. These delays have the potential to adversely affect our 2024 sidetrack drilling and workover programs. Please see "—Regulatory Matters" in this Quarterly Report, as well as in our Annual Report, for additional discussion of the laws and regulations that impact our ability to drill and develop our assets, including those impacting regulatory approval and permitting requirements.

Exclusive of the capital expenditures noted above, for the full year 2024, we plan to spend approximately $21 million to $24 million on plugging and abandonment activities, most of which is planned to meet our annual obligation requirements under California idle well program. We spent approximately $2 million for plugging and abandonment activities in the three months ended March 31, 2024.

For information about the potential risks related to our capital program, see Part I, Item IA. "Risk factors" in our Annual Report, as well as "—Regulatory Matters."

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		
	March 31, 2024	December 31, 2023	March 31, 2023
Average daily production:[1]			
Oil (mbbl/d)	23.8	24.0	22.6
Natural Gas (mmcf/d)	7.9	7.8	8.7
NGL (mbbl/d)	0.3	0.6	0.2
Total (mboe/d)[2]	25.4	25.9	24.3
Total Production:			
Oil (mbbl)	2,161	2,209	2,037
Natural gas (mmcf)	723	717	779
NGLs (mbbl)	28	56	20
Total (mboe)[2]	2,310	2,384	2,187
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 75.31	$ 76.00	$ 74.69
Effects of scheduled derivative settlements ($/bbl)	$ (2.17)	$ (3.35)	$ (3.65)
Oil with hedges ($/bbl)	$ 73.14	$ 72.65	$ 71.04
Natural gas ($/mcf)	$ 3.76	$ 4.48	$ 17.39
NGL ($/bbl)	$ 29.60	$ 24.01	$ 34.10
Average Benchmark prices:			
Oil (bbl) – Brent	$ 81.76	$ 82.85	$ 82.16
Oil (bbl) – WTI	$ 77.02	$ 78.49	$ 76.15
Natural gas (mmbtu) – SoCal Gas city-gate[3]	$ 4.21	$ 6.25	$ 24.81
Natural gas (mmbtu) – Northwest, Rocky Mountains[4]	$ 3.41	$ 4.53	$ 22.36
Natural gas (mmbtu) – Henry Hub[4]	$ 2.15	$ 2.74	$ 2.64

(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 March 31, 2024, the average prices of Brent oil and Henry Hub natural gas were $81.76 per bbl and $2.15 per mmbtu.

(3) The natural gas we purchase to generate steam and electricity is primarily based on Rockies price indexes, including transportation charges, as we currently purchase a substantial majority of our gas needs from the Rockies, with the balance purchased in California. SoCal Gas city-gate Index is the relevant index used only for the portion of gas purchases in California. Beginning in the first quarter of 2023, we are purchasing a majority of our fuel gas in the Rockies; most of the purchases made in California utilize the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases was Kern, Delivered.

(4) Most of our gas purchases and gas sales in the Rockies are predicated on the Northwest, Rocky Mountains index, and to a lesser extent based on Henry Hub.

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

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
Average daily production (mboe/d):[1]			
California	21.3	21.5	19.9
Utah	4.1	4.4	4.4
Total average daily production	25.4	25.9	24.3

(1) Production represents volumes sold during the period.

Our average daily production decreased 2%, or 0.5 mboe/d, for the three months ended March 31, 2024, compared to the three months ended December 31, 2023. Our California production was 21.3 mboe/d for the first quarter of 2024, a decrease of less than 1% or 0.2 mboe/d from the fourth quarter of 2023, which was principally due to the natural decline experienced by the wells placed in service in late 2023. This decrease was partially offset by production from development activities as well as the impact of the year end acquisition. The Utah decline was due to lower drilling and workover activity as 2024 development plans are expected to begin in the second quarter (see “—Capital Expenditures” for further discussion).

Our average daily production increased 5%, or 1.1 mboe/d, for the three months ended March 31, 2024 compared to the three months ended March 31, 2023. Higher 2024 production in California was due to the bolt-on acquisitions in late 2023 and increased well operating time from improved weather conditions and less abandonment activity. California production was negatively impacted in the first quarter of 2023 by severe rainstorms which lowered operating times and prevented routine well maintenance. The decrease in Utah was due to a reduction of drilling and workover activity.

Results of Operations

Three Months Ended March 31, 2024 compared to Three Months Ended December 31, 2023.

	Three Months Ended			
	March 31, 2024	December 31, 2023	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 166,318	$ 172,439	$ (6,121)	(4) %
Service revenue[(1)]	31,683	40,746	(9,063)	(22) %
Electricity sales	4,243	2,905	1,338	46 %
(Losses) gains on oil and gas sales derivatives	(71,200)	83,918	(155,118)	n/a
Other revenues	67	319	(252)	(79) %
Total revenues and other	$ 131,111	$ 300,327	$ (169,216)	(56) %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $35 million and $43 million, and after the intercompany elimination of $4 million and $2 million, net service revenue was approximately $32 million and approximately $41 million for the quarters ended March 31, 2024 and December 31, 2023, respectively.

Revenues and Other

Oil, natural gas and NGL sales decreased by $6 million, or 4%, to approximately $166 million for the three months ended March 31, 2024, compared to the three months ended December 31, 2023. The decrease was driven by a $4 million decrease in oil volumes and $2 million decrease in oil prices.

Service revenue consisted entirely of revenue from the well servicing and abandonment business. Service revenue decreased by $9 million, or 22%, to approximately $32 million for the three months ended March 31, 2024, compared to the three months ended December 31, 2023. The decrease was driven by lower activity in the first quarter of 2024 and a shift in services from third parties to our E&P segment.

Electricity sales represent sales to utilities and increased $1 million, or 46%, to approximately $4 million for the three months ended March 31, 2024 compared to the three months ended December 31, 2023. This increase was due to higher resource adequacy payments in the first quarter of 2024.

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 March 31, 2024 and December 31, 2023 was $5 million and $7 million, respectively. This quarter-over-quarter decrease in settlement loss was primarily due to a higher fixed price of settled positions and lower Brent settlement prices, the index for all our oil derivatives. The mark-to-market non-cash loss for the three months ended March 31, 2024 was $67 million compared to a gain of $91 million in the three months ended December 31, 2023. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Other revenues were not material for the three months ended March 31, 2024 and December 31, 2023.

	Three Months Ended			
	March 31, 2024	December 31, 2023	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 60,697	$ 67,342	$ (6,645)	(10)%
Costs of services[(1)]	27,304	32,783	(5,479)	(17)%
Electricity generation expenses	1,093	1,827	(734)	(40)%
Transportation expenses	1,059	1,260	(201)	(16)%
Acquisition costs[(2)]	2,617	284	2,333	821 %
General and administrative expenses	20,234	20,729	(495)	(2)%
Depreciation, depletion and amortization	42,831	40,937	1,894	5 %
Taxes, other than income taxes	15,689	15,826	(137)	(1)%
Losses (gains) on natural gas purchase derivatives	4,481	21,397	(16,916)	(79)%
Other operating (income) expense	(133)	36	(169)	469 %
Total expenses and other	175,872	202,421	(26,549)	(13)%
Other expenses:				
Interest expense	(9,140)	(9,680)	540	(6)%
Other, net	(83)	(10)	(73)	730 %
Total other expenses	(9,223)	(9,690)	467	(5)%
(Loss) income before income taxes	(53,984)	88,216	(142,200)	(161)%
Income tax (benefit) expense	(13,900)	25,665	(39,565)	154 %
Net (loss) income	$ (40,084)	$ 62,551	$ (102,635)	(164)%
Adjusted EBITDA[(3)]	$ 68,534	$ 70,036	$ (1,502)	(2)%
Adjusted Net Income[(3)]	$ 10,910	$ 10,426	$ 484	5 %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $31 million and $35 million, and after the intercompany elimination of $4 million and $2 million, net costs of services was $27 million and $33 million for the quarters ended March 31, 2024 and December 31, 2023, respectively.

(2) Includes legal and other professional expenses related to various transaction activities.

(3) Adjusted EBITDA and Adjusted Net Income (Loss) are financial measures that are not calculated in accordance with GAAP. For definitions and a reconciliation to the Net Cash Provided by Operating Activities and Net Income (loss), please see "—Non-GAAP Financial Measures".

Expenses

Lease operating expenses, which do not include the effects of gas purchase hedges, decreased 10% or $7 million to $61 million for the first quarter of 2024 when compared to the fourth quarter of 2023. The majority of this decrease was the result of lower natural gas (fuel) costs of $8 million for our California steam generation facilities due to a decline in fuel prices. Lease operating expenses, excluding fuel, increased $1 million due to higher well service and maintenance activity.

Cost of services decreased $5 million, or 17%, to $27 million in the first quarter of 2024 due to lower activity.

Electricity generation decreased $1 million due to lower fuel prices for the three months ended March 31, 2024 compared to the three months ended December 31, 2023.

Transportation expenses were comparable for the periods presented.

Gains and losses on natural gas purchase derivatives resulted in a loss of $4 million for the three months ended March 31, 2024 and a loss of $21 million for the three months ended December 31, 2023. Settlements for the three months ended March 31, 2024 and December 31, 2023 were a loss of $4 million, or $1.91 per boe, and a loss of $2 million, or $0.93 per boe, respectively. The increased loss was due to an decrease in settlement price relative to the fixed price in the first quarter of 2024 compared to the fourth quarter of 2023. The mark-to-market valuation loss for the three months ended March 31, 2024 was $0.1 million compared to a loss of $19 million for the three months ended December 31, 2023. Because we are the fixed price payer on these natural gas swaps, generally, period to period increases (decreases) in the associated price index create valuation gains (losses).

Acquisition costs increased $2 million for the three months ended March 31, 2024 compared to the three months ended December 31, 2023, and includes legal and other professional expenses related to various transaction activities.

General and administrative expenses were flat at $20 million for the three months ended March 31, 2024, compared to the three months ended December 31, 2023. For the three months ended March 31, 2024, general and administrative expenses included immaterial non-cash stock compensation costs, the result of stock award forfeitures, compared to $3 million for three months ended December 31, 2023. We incurred non-recurring costs related to severance of approximately $1 million for the three months ended March 31, 2024 and none for the three months ended December 31, 2023.

Adjusted General and Administrative Expenses, which excludes non-cash stock compensation expense and non-recurring costs, increased $1 million primarily due to higher payroll taxes driven by stock vestings for the three months ended March 31, 2024 compared to the three months ended December 31, 2023. See “—Non-GAAP Financial Measures” for a reconciliation of general and administrative expenses, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A increased $2 million for the three months ended March 31, 2024 compared to the three months ended December 31, 2023 due to higher depletion rates.

Taxes, Other Than Income Taxes

	Three Months Ended			
	March 31, 2024	**December 31, 2023**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 1.67	$ 1.41	$ 0.26	18 %
Ad valorem and property taxes	2.51	1.96	0.55	28 %
Greenhouse gas allowances and other emission costs	2.61	3.27	(0.66)	(20) %
Total taxes other than income taxes	$ 6.79	$ 6.64	$ 0.15	2 %

Taxes, other than income taxes, increased in the three months ended March 31, 2024 by $0.15 per boe, or 2%, to $6.79. The increase in ad valorem and property taxes is due to increased property values in part due to the additional properties acquired in 2023. This is partially offset by a decrease in greenhouse gas allowance expense due to lower mark-to-market-prices.

Interest Expense

Interest expense increased $1 million for the three months ended March 31, 2024, compared to the three months ended December 31, 2023 as we had higher working capital borrowings on the RBL Facility.

Income Taxes

Our effective tax rate was 26% for the three months ended March 31, 2024 and 29% for the three months ended December 31, 2023. The rate in both periods included the impact of certain permanent items which were not deductible.

Three Months Ended March 31, 2024 compared to Three Months Ended March 31, 2023.

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 166,318	$ 166,357	$ (39)	— %
Service revenue[1]	31,683	44,623	(12,940)	(29) %
Electricity sales	4,243	5,445	(1,202)	(22) %
(Losses) gains on oil and gas sales derivatives	(71,200)	38,499	(109,699)	n/a
Other revenues	67	45	22	49 %
Total revenues and other	$ 131,111	$ 254,969	$ (123,858)	(49) %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $35 million and $46 million, and after the intercompany elimination of $4 million and $2 million, net service revenue was approximately $32 million and approximately $45 million for the quarters ended March 31, 2024 and 2023, respectively.

Revenues and Other

Oil, natural gas and NGL sales were flat at approximately $166 million for the three months ended March 31, 2024 when compared to the three months ended March 31, 2023. Oil sales revenue increased approximately $11 million, primarily from higher sales volume, and was offset by the effect of lower natural gas prices.

Service revenue decreased by $13 million to $32 million for the three months ended March 31, 2024, compared to the three months ended March 31, 2023, due to lower activity and a shift in service from third parties to our E&P segment.

Electricity sales represent sales to utilities and decreased $1 million, or 22%, to $4 million for the three months ended March 31, 2024 when compared to the three months ended March 31, 2023. This decrease was due to lower energy prices partially offset by higher resource adequacy revenue.

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 for the three months ended March 31, 2024 and March 31, 2023 were $5 million and $7 million, respectively. The decrease in settlement losses was driven by lower oil prices relative to our derivative fixed prices in the first quarter of 2024 than that of the same period in 2023. Notional volumes were 17 mbbl/d in the first quarter of 2024 and 15 mbbl/d in the first quarter of 2023. The mark-to-market non-cash loss for the three months ended March 31, 2024 was $67 million and a gain of $46 million for the three months ended March 31, 2023. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Other revenues were not material for the three months ended March 31, 2024 and March 31, 2023.

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 60,697	$ 134,835	$ (74,138)	(55)%
Costs of services(1)	27,304	36,099	(8,795)	(24)%
Electricity generation expenses	1,093	2,500	(1,407)	(56)%
Transportation expenses	1,059	1,041	18	2 %
Acquisition costs(2)	2,617	—	2,617	100 %
General and administrative expenses	20,234	31,669	(11,435)	(36)%
Depreciation, depletion and amortization	42,831	40,121	2,710	7 %
Taxes, other than income taxes	15,689	10,460	5,229	50 %
Losses (gains) on natural gas purchase derivatives	4,481	(610)	5,091	n/a
Other operating (income)	(133)	(286)	(153)	53 %
Total expenses and other	175,872	255,829	(79,957)	(31)%
Other expenses:				
Interest expense	(9,140)	(7,837)	(1,303)	17 %
Other, net	(83)	(75)	(8)	11 %
Total other expenses	(9,223)	(7,912)	(1,311)	17 %
Loss before income taxes	(53,984)	(8,772)	(45,212)	515 %
Income tax (benefit)	(13,900)	(2,913)	(10,987)	(377)%
Net loss	$ (40,084)	$ (5,859)	$ (34,225)	584 %
Adjusted EBITDA(3)	$ 68,534	$ 59,337	$ 9,197	15 %
Adjusted Net Income(3)	$ 10,910	$ 5,307	$ 5,603	106 %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $31 million and $38 million, and after the intercompany elimination of $4 million and $2 million, net costs of services was $27 million and $36 million for the quarters ended March 31, 2024 and December 31, 2023, respectively.

(2) Includes legal and other professional expenses related to various transactions activities.

(3) Adjusted EBITDA and Adjusted Net Income (Loss) are financial measures that are not calculated in accordance with GAAP. For definitions and a reconciliation to the Net Cash Provided by Operating Activities and Net Income (loss), please see "—Non-GAAP Financial Measures".

Expenses

Lease operating expenses, which do not include the effects of gas purchase hedges, decreased 55% or $74 million on an absolute dollar basis to $61 million for the first quarter of 2024 when compared to the first quarter of 2023. The decrease was the result of $75 million lower natural gas (fuel) costs for our California steam generation facilities due to a decline in fuel prices, partially offset by a $1 million increase in non-fuel lease operating expense.

Cost of services decreased $9 million, or 24%, to $27 million for the first quarter of 2024 compared to the first quarter of 2023 primarily due to lower activity.

Electricity generation expenses decreased $1 million, or 56%, to $1 million for the three months ended March 31, 2024 compared to the same period in 2023 due to a decrease in fuel prices.

Gains and losses on natural gas purchase derivatives for the three months ended March 31, 2024 and March 31, 2023 resulted in a loss of $4 million and a gain of $1 million, respectively. Settlements for the three months ended March 31, 2024 were a loss of $4 million, or $1.91 per boe, and a gain of $55 million or $25.11 per boe for the three months ended March 31, 2023. The change in settlements was due to a decline in natural gas index prices below the fixed price of settled positions. The mark-to-market non-cash loss was $0.1 million for the three months ended March 31, 2024 and $54 million for three months ended March 31, 2023. Because we are the fixed price payer on these natural gas swaps, generally, period to period increases (decreases) in the associated price index create valuation gains (losses).

Transportation expenses were comparable for the periods presented.

Acquisition costs increased $3 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023, and includes legal and other professional expenses related to various transaction activities.

General and administrative expenses decreased $11 million or 36% in the three months ended March 31, 2024 when compared to the three months ended March 31, 2023. For the three months ended March 31, 2024 general and administrative expenses had an immaterial amount of non-cash stock compensation expense, the result of stock award forfeitures, compared to $5 million for March 31, 2023. We incurred non-recurring costs of $1 million for the three months ended March 31, 2024 compared to $7 million for the three months ended March 31, 2023.

Adjusted General and Administrative Expenses, which exclude non-cash stock compensation expense and non-recurring costs decreased $1 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023. The decrease was the result of lower professional services and employee compensation costs. See "—Non-GAAP Financial Measures" for a reconciliation of general and administrative expenses, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A increased $3 million, or 7%, to $43 million in the three months ended March 31, 2024 when compared to the three months ended March 31, 2023 due to an increase in depletion rates.

Taxes, Other Than Income Taxes

	Three Months Ended March 31,			
	2024	**2023**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 1.67	$ 1.81	$ (0.14)	(8) %
Ad valorem and property taxes	2.51	2.21	0.30	14 %
Greenhouse gas allowances and other emission costs	2.61	0.76	1.85	243 %
Total taxes other than income taxes	$ 6.79	$ 4.78	$ 2.01	42 %

Taxes, other than income taxes increased 42% to $6.79 per boe for the three months ended March 31, 2024, compared to $4.78 per boe for the three months ended March 31, 2023. The GHG allowance expense increase was due to higher mark-to-market prices in the first quarter of 2024. The increase in ad valorem and property taxes is due to increased property values in part due to the additional properties acquired in 2023.

Interest Expense

Interest expense increased $1 million, or 17%, in the three months ended March 31, 2024 when compared to the three months ended March 31, 2023 as we had higher working capital borrowings on the RBL Facility.

Income Taxes

Our effective tax rate was approximately 26% for the three months ended March 31, 2024 compared to approximately 33% for the three months ended March 31, 2023. The rate in both periods included the impact of certain permanent items which were not deductible.

E&P Field Operations

	Three Months Ended			
	March 31, 2024	December 31, 2023	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 26.28	$ 28.25	$ (1.97)	(7) %
Electricity generation expenses	0.47	0.77	(0.30)	(39) %
Transportation expenses	0.46	0.53	(0.07)	(13) %
Total	$ 27.21	$ 29.55	$ (2.34)	(8) %
Cash settlements paid for gas purchase hedges	$ 1.91	$ 0.93	$ 0.98	105 %
E&P non-production revenues				
Electricity sales	$ 1.84	$ 1.22	$ 0.62	51 %
Transportation sales	0.03	0.13	(0.10)	(77) %
Total	$ 1.87	$ 1.35	$ 0.52	39 %

	Three Months Ended			
	March 31, 2024	March 31, 2023	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 26.28	$ 61.65	$ (35.37)	(57)%
Electricity generation expenses	0.47	1.14	(0.67)	(59)%
Transportation expenses	0.46	0.48	(0.02)	(4)%
Total	$ 27.21	$ 63.27	$ (36.06)	(57)%
Cash settlements paid (received) for gas purchase hedges	$ 1.91	$ (25.11)	$ 27.02	(108)%
E&P non-production revenues				
Electricity sales	$ 1.84	$ 2.49	$ (0.65)	(26)%
Transportation sales	0.03	0.02	0.01	50 %
Total	$ 1.87	$ 2.51	$ (0.64)	(25)%

See “—How We Plan and Evaluate Operations” for details.

Non-GAAP Financial Measures

Adjusted EBITDA, Adjusted 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), Adjusted Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either net income (loss) or cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses 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 unusual and infrequent items. 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. We also use Adjusted EBITDA in planning our capital expenditure allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility.

We define Adjusted Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and capital expenditures. In 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and capital expenditures. This update better aligns with the full capital expenditure requirements of the Company. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital. Management believes Adjusted Free Cash Flow may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base after maintaining the existing production volumes of that asset base to return capital to stockholders, fund further business expansion through acquisitions or investments in our existing asset base to increase production volumes and pay other non-discretionary expenses. Management also uses Adjusted Free Cash Flow as the primary metric to plan for future growth.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from this measure.

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, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our statutory tax rate. 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 believe Adjusted Net Income (Loss) is useful to investors because it reflects how management evaluates the Company’s ongoing financial and operating performance from period-to-period after removing certain transactions and activities that affect comparability of the metrics and are not reflective of the Company’s core operations. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

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 believe Adjusted General and Administrative Expenses is useful to investors because it reflects how management evaluates the Company’s ongoing general and administrative expenses from period-to-period after removing non-cash stock compensation, as well as unusual or infrequent costs that affect comparability of the metrics and are not reflective of the Company’s administrative costs. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

While Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses 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 and should not be considered as an alternative to, or more meaningful than 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 Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

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

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
	(in thousands)		
Adjusted EBITDA reconciliation:			
Net (loss) income	$ (40,084)	$ 62,551	$ (5,859)
Add (Subtract):			
Interest expense	9,140	9,680	7,837
Income tax (benefit) expense	(13,900)	25,665	(2,913)
Depreciation, depletion and amortization	42,831	40,937	40,121
Losses (gains) on derivatives	75,681	(62,521)	(39,109)
Net cash (paid) received for scheduled derivative settlements	(9,094)	(9,616)	47,467
Other operating (income) expenses	(133)	36	(286)
Stock compensation expense(1)	385	3,020	4,766
Acquisition costs(2)	2,617	284	—
Non-recurring costs(3)	1,091	—	7,313
Adjusted EBITDA	$ 68,534	$ 70,036	$ 59,337

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
	(in thousands)		
Adjusted EBITDA reconciliation:			
Net cash provided by operating activities	$ 27,273	$ 79,018	$ 1,781
Add (Subtract):			
Cash interest payments	15,256	1,794	14,388
Cash income tax payments	—	525	—
Acquisition costs(2)	2,617	284	—
Non-recurring costs(3)	1,091	—	7,313
Changes in operating assets and liabilities - working capital(4)	22,543	(11,070)	36,745
Other operating (income) expenses - cash portion(5)	(246)	(515)	(890)
Adjusted EBITDA	$ 68,534	$ 70,036	$ 59,337

(1) Decrease in the first quarter of 2024 is the result of stock award forfeitures.

(2) Includes legal and other professional expenses related to various transaction activities.

(3) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

(4) Changes in other assets and liabilities consists of working capital and various immaterial items.

(5) Represents the cash portion of other operating (income) expenses from the income statement, net of the non-cash portion in the cash flow statement.

The following table presents a reconciliation of the GAAP financial measure of operating cash flow to the non-GAAP financial measure of Adjusted Free Cash Flow for each of the periods indicated. We use Adjusted Free Cash Flow for our shareholder return model.

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
	(in thousands)		
Adjusted Free Cash Flow reconciliation:			
Net cash provided by operating activities[(1)]	$ 27,273	$ 79,018	$ 1,781
Subtract:			
Capital expenditures[(2)]	(16,936)	(15,114)	(19,272)
Fixed dividends[(3)]	(9,233)	(9,080)	(9,190)
Adjusted Free Cash Flow	$ 1,104	$ 54,824	$ (26,681)

____

(1) On a consolidated basis.

(2) In 2024, we updated Adjusted Free Cash Flow to include all capital expenditures in the calculation of Adjusted Free Cash Flow. This update better aligns with the full capital expenditure requirements of the Company. In 2023, the definition of capital expenditures was the required amount to keep annual production essentially flat (maintenance capital), calculated as the capital expenditures for the E&P business for the periods presented. We did not retrospectively adjust 2023.

	Three Months Ended	
	December 31, 2023	March 31, 2023
	(in thousands)	
Consolidated capital expenditures[(a)]	$ (17,003)	$ (20,633)
Excluded items[(b)]	1,889	1,361
Maintenance capital	$ (15,114)	$ (19,272)

____

(a) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.

(b) Comprised of the capital expenditures in our E&P segment that are related to strategic business expansion, such as acquisitions of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in our well servicing and abandonment segment and corporate expenditures that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the three months ended December 31, 2023 and March 31, 2023, we excluded approximately $1 million of capital expenditures related to our well servicing and abandonment segment, for both periods presented, which was substantially all used for sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the three months ended December 31, 2023 and March 31, 2023, we excluded approximately $0.5 million and $0.4 million of corporate capital expenditures, respectively, which we determined was not related to the maintenance of our baseline production.

(3) Represents fixed dividends declared for the periods presented.

The following table presents a reconciliation of the GAAP financial measures of net income (loss) and net income (loss) per share — diluted to the non-GAAP financial measures of Adjusted Net Income (Loss) and Adjusted Net Income (Loss) per share — diluted for each of the periods indicated.

	Three Months Ended					
	March 31, 2024		December 31, 2023		March 31, 2023	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:						
Net (loss) income	$ (40,084)	$ (0.52)	$ 62,551	$ 0.81	$ (5,859)	$ (0.07)
Add (Subtract):						
Losses (gains) on derivatives	75,681	0.98	(62,521)	(0.81)	(39,109)	(0.49)
Net cash (paid) received for scheduled derivative settlements	(9,094)	(0.12)	(9,616)	(0.12)	47,467	0.60
Other operating (income) expenses	(133)	—	36	—	(286)	(0.01)
Acquisition costs[1]	2,617	0.03	284	—	—	—
Non-recurring costs[2]	1,091	0.02	—	—	7,313	0.09
Total additions (subtractions), net	70,162	0.91	(71,817)	(0.93)	15,385	0.19
Income tax (benefit) expense of adjustments[3]	(19,168)	(0.25)	19,692	0.25	(4,219)	(0.05)
Adjusted Net Income	$ 10,910	$ 0.14	$ 10,426	$ 0.13	$ 5,307	$ 0.07
Basic EPS on Adjusted Net Income	$ 0.14		$ 0.14		$ 0.07	
Diluted EPS on Adjusted Net Income	$ 0.14		$ 0.13		$ 0.07	
Weighted average shares of common stock outstanding - basic	76,254		75,667		76,112	
Weighted average shares of common stock outstanding - diluted	77,373		77,349		79,210	

(1) Includes legal and other professional expenses related to various transaction activities.

(2) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

(3) The federal and state statutory rates were utilized for all periods presented.

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

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
	(in thousands)		
Adjusted General and Administrative Expense reconciliation:			
General and administrative expenses	$ 20,234	$ 20,729	$ 31,669
Subtract:			
Non-cash stock compensation expense (G&A portion)[1]	(200)	(2,843)	(4,619)
Non-recurring costs[2]	(1,091)	—	(7,313)
Adjusted general and administrative expenses	$ 18,943	$ 17,886	$ 19,737
Well servicing and abandonment segment	$ 2,929	$ 2,177	$ 3,126
E&P segment, and corporate	$ 16,014	$ 15,709	$ 16,611
E&P segment, and corporate ($/boe)	$ 6.93	$ 6.59	$ 7.60
Total mboe	2,310	2,384	2,187

(1) Decrease in the first quarter of 2024 is the result of stock award forfeitures.

(2) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

Liquidity and Capital Resources

As of March 31, 2024, we had liquidity of $149 million, consisting of $3 million cash, $139 million available for borrowings under our 2021 RBL Facility and $7 million available for borrowings under our 2022 ABL Facility (as defined below). Based on current commodity prices and our development success rate to date, we expect to be able to fund our 2024 capital development programs from cash flow from operations.

We review the allocations under our shareholder return model from time to time based on industry conditions, operational results and other factors. In 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and all capital expenditures. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital. Our goal is to continue maximizing enterprise value through overall returns. Beginning in 2023, the annual allocation of Adjusted Free Cash Flow has been (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. Any dividends (fixed or variable) actually paid will be determined by our Board of Directors in light of then existing conditions and circumstances, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors. From time to time we consider bolt-on acquisitions, which may be used to maintain our existing production volumes or may support strategic growth, and could be at least partially funded by reallocating a portion of our capital expenditures, as a way of increasing Adjusted Free Cash Flow.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have non-discretionary expenditures that are not deducted from this measure. Adjusted Free Cash Flow is a non-GAAP financial measure. See “Management’s Discussion and Analysis—Non-GAAP Financial Measures” for a reconciliation of the GAAP financial measure of operating cash flow, our most directly comparable financial measure calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted Free Cash Flow.

We currently believe that our liquidity, capital resources and cash will be sufficient to conduct our business and operations and meet our obligations for at least the next 12 months. In the longer term, if oil prices were to significantly decline and remain weak, we may not be able to continue to generate the same level of Adjusted 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” in this Quarterly Report and Part I, Item 1A. “Risk Factors” in our Annual Report 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.

2021 RBL Facility

See Note 2—Debt in the Notes to Consolidated Financial Statements in Part I, Item 1. “Financial Statements” of this Quarterly Report for details.

2022 ABL Facility

See Note 2—Debt in the Notes to Consolidated Financial Statements in Part I, Item 1. “Financial Statements” of this Quarterly Report for details.

Senior Unsecured Notes

In February 2018, Berry LLC completed a private issuance of $400 million in aggregate principal amount of 7.0% senior unsecured notes due February 2026, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount.

The 2026 Notes are Berry LLC's senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The 2026 Notes are fully and unconditionally guaranteed on a senior unsecured basis by Berry Corp and certain of its subsidiaries. C&J and C&J Management do not guarantee the 2026 Notes. Macpherson Energy and certain of its subsidiaries became guarantors of the 2026 Notes on January 4, 2024 and February 8, 2024 pursuant to supplemental indentures.

The indenture governing the 2026 Notes contains customary covenants and events of default (in some cases, subject to grace periods). We were in compliance with all covenants under the 2026 Notes as of March 31, 2024.

Debt Repurchase Program

In February 2020, the board of directors (the "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 do not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any notes under this program.

Hedging

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including swaps, puts, calls and collars. 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. We have also entered into gas transportation contracts in the Rockies to help reduce the price fluctuation exposure, however these do not qualify as hedges.

In addition, we also hedge to meet the hedging requirements of the 2021 RBL Facility. The 2021 RBL Facility requires us to maintain commodity hedges (other than three-way collars) on minimum notional volumes of (i) at least 75% of our reasonably projected production of crude oil from our PDP reserves, for 24 full calendar months after the effective date of the 2021 RBL Facility and after each May 1 and November 1 of each calendar year and (ii) at least 50% of our reasonably projected production of crude oil from our PDP reserves, for each full calendar month during the period from and including the 25th full calendar month following each such Minimum Hedging Requirement Date through and including the 36th full calendar month following each such Minimum Hedging Requirement Date; provided, that in the case of each of the above clauses (i) and (ii), the notional volumes hedged are deemed reduced by the notional volumes of any short puts or other similar derivatives having the effect of exposing us to commodity price risk below the "floor."

In addition to minimum hedging requirements and other restrictions in respect of hedging described therein, the 2021 RBL Facility contains restrictions on our commodity hedging which prevent us from entering into hedging agreements (i) with a tenor exceeding 48 months or (ii) for notional volumes which (when aggregated with other hedges then in effect other than basis differential swaps on volumes already hedged) exceed, as of the date such hedging agreement is executed, 90% of our reasonably projected production of crude oil from our PDP reserves, for each month following the date such hedging agreement is entered into, provided that the volume limitations above do not apply to short puts or put options contracts that are not related to corresponding calls, collars, or swaps.

Our generally low-decline production base 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 current hedging positions. For information regarding risks related to our hedging program, see Part I—Item 1A. "Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

As of April 30, 2024, we had the following crude oil production and gas purchases hedges.

		Q2 2024		Q3 2024		Q4 2024		FY 2025		FY 2026		FY 2027
Brent - Crude Oil production												
Swaps												
Hedged volume (bbls)		1,611,294		1,481,749		1,438,656		4,859,125		2,039,268		540,000
Weighted-average price ($/bbl)	$	78.97	$	76.88	$	76.93	$	76.08	$	71.11	$	71.42
Sold Calls(1)												
Hedged volume (bbls)		91,000		92,000		92,000		296,127		1,251,500		—
Weighted-average price ($/bbl)	$	105.00	$	105.00	$	105.00	$	88.69	$	85.53	$	—
Purchased Puts (net)(2)												
Hedged volume (bbls)		318,500		322,000		322,000		—		—		—
Weighted-average price ($/bbl)	$	50.00	$	50.00	$	50.00	$	—	$	—	$	—
Purchased Puts (net)(2)												
Hedged volume (bbls)		—		—		—		296,127		1,251,500		—
Weighted-average price ($/bbl)	$	—	$	—	$	—	$	60.00	$	60.00	$	—
Sold Puts (net)(2)												
Hedged volume (bbls)		45,500		46,000		46,000		—		—		—
Weighted-average price ($/bbl)	$	40.00	$	40.00	$	40.00	$	—	$	—	$	—
NWPL - Natural Gas purchases(3)												
Swaps												
Hedged volume (mmbtu)		3,640,000		3,680,000		3,680,000		13,380,000		3,040,000		—
Weighted-average price ($/mmbtu)	$	3.96	$	3.96	$	3.96	$	4.27	$	4.26	$	—

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.

(2) Purchased puts and sold puts with the same strike price have been presented on a net basis.

(3) The term “NWPL” is defined as Northwest Rocky Mountain Pipeline.

(Losses) gains on Derivatives

A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
		(in thousands)	
Realized (losses) gains on commodity derivatives:			
Realized (losses) on oil sales derivatives	$ (4,682)	$ (7,405)	$ (7,438)
Realized (losses) gains on natural gas purchase derivatives	(4,412)	(2,211)	54,905
Total realized (losses) gains on derivatives	$ (9,094)	$ (9,616)	$ 47,467
Unrealized (losses) gains on commodity derivatives:			
Unrealized (losses) gains on oil sales derivatives	$ (66,518)	$ 91,323	$ 45,937
Unrealized (losses) on natural gas purchase derivatives	(69)	(19,186)	(54,295)
Total unrealized (losses) gains on derivatives	$ (66,587)	$ 72,137	$ (8,358)
Total (losses) gains on derivatives	$ (75,681)	$ 62,521	$ 39,109

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

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
Crude Oil (per bbl):			
Realized sales price, before the effects of derivative settlements	$ 75.31	$ 76.00	$ 74.69
Effects of derivative settlements	(2.17)	(3.35)	(3.65)
Realized sales price, after the effects of derivatives	$ 73.14	$ 72.65	$ 71.04
Purchased Natural Gas (per mmbtu):			
Purchase price, before the effects of derivative settlements	$ 3.99	$ 5.29	$ 20.74
Effects of derivative settlements	0.92	0.44	(11.86)
Purchase price, after the effects of derivatives settlements	$ 4.91	$ 5.73	$ 8.88

Cash Dividends

In the first quarter of 2024, our Board of Directors declared a quarterly fixed cash dividend totaling $0.12 per share, as well as a variable cash dividend of $0.14 per share which was based on the results of the fourth quarter of 2023, for a total of $0.26 per share, which we paid in March 2024. In April 2024, The Board of Directors approved a fixed cash dividend totaling $0.12 per share, which is expected to be paid in May 2024.

The following table represents the regular fixed cash dividends on our common stock and variable dividends approved by our Board of Directors in 2024.

	First Quarter
Fixed Dividends	$ 0.12
Variable Dividends(1)	—
Total	$ 0.12

(1) Variable Dividends are declared the quarter following the period of results (the period used to determine the variable divided based on the shareholder return model). The table notes total dividends earned in each quarter. There is no variable dividend related to the results of the first quarter of 2024.

The Company anticipates that it will continue to pay quarterly cash dividends in the future. However, the payment and amount of future dividends remain within the discretion of the Board of Directors and will depend upon the Company's future earnings, financial condition, capital requirements and other factors.

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended March 31, 2024. As of March 31, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $114 million in aggregate. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of March 31, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and the share repurchase program does not obligate the Company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Three Months Ended March 31,	
	2024	**2023**
	(in thousands)	
Net cash:		
Provided by operating activities	$ 27,273	$ 1,781
Used in investing activities	(18,661)	(30,460)
Used in financing activities	(9,990)	(3,454)
Net (decrease) in cash and cash equivalents	$ (1,378)	$ (32,133)

Operating Activities

Cash provided by operating activities increased for the three months ended March 31, 2024 by approximately $25 million when compared to the three months ended March 31, 2023. The increase was primarily related to a decrease in lease operating expenses (largely fuel gas purchases), royalty payments and executive transition costs, partially offset by an increase in derivative settlements paid.

Investing Activities

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

	Three Months Ended March 31,	
	2024	**2023**
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (16,936)	$ (20,633)
Changes in capital expenditures accruals	(957)	(6,170)
Acquisitions, net of cash received	(768)	(3,657)
Net cash used in investing activities	$ (18,661)	$ (30,460)

Cash used in investing activities decreased $12 million for the three months ended March 31, 2024 when compared to the same period in 2023, primarily due to lower capital expenditures as we drilled fewer wells in the first quarter of 2024. However, we increased production utilizing less capital due to the bolt-on acquisitions in the second half of 2023.

Financing Activities

Cash used in financing activities decreased approximately $7 million for the three months ended March 31, 2024 when compared to the three months ended March 31, 2023 primarily due to decreased dividends paid, partially offset by decreased borrowings under the 2021 RBL credit facility.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2023 to March 31, 2024 are discussed below.

	March 31, 2024		December 31, 2023	
	(in thousands)			
Cash and cash equivalents	$	3,457	$	4,835
Accounts receivable, net	$	89,937	$	86,918
Derivative instruments assets - current and long-term	$	—	$	10,751
Other current assets	$	45,979	$	43,759
Property, plant & equipment, net	$	1,384,704	$	1,406,612
Deferred income taxes asset - long-term	$	41,455	$	30,308
Other noncurrent assets	$	9,984	$	10,975
Accounts payable and accrued expenses	$	184,539	$	213,401
Derivative instruments liabilities - current and long-term	$	66,575	$	10,740
Long-term debt	$	448,121	$	427,993
Deferred income taxes liability - long-term	$	—	$	2,344
Asset retirement obligations - long-term	$	177,900	$	176,578
Other noncurrent liabilities	$	9,537	$	5,126
Stockholders' equity	$	688,844	$	757,976

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

The $3 million increase in accounts receivable was primarily due to an increase in oil sales prices comparatively at the end of each period.

The $22 million decrease in property, plant and equipment was primarily due to year-to-date DD&A of $40 million offset by $17 million in capital investments and $1 million in acquisitions.

The $11 million increase in deferred income taxes assets - long term was primarily due to the tax effect of the book loss in the first quarter. The asset now reflects both federal and state tax amounts whereas the year end balance only reflected federal taxes.

The $29 million decrease in accounts payable and accrued expenses included decreased fuel gas purchases and payments in the first quarter 2024 (without similar fourth quarter 2023 payments) for royalties, interest and annual incentive compensation.

The $67 million increase in net derivative liability, which includes the derivative asset, is due to the increase in the net liability of $0 million at December 31, 2023 to $67 million as of March 31, 2024. 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 $20 million increase in long-term debt largely reflected first quarter borrowings on our 2021 RBL Facility related to typical first quarter working capital needs.

The $2 million decrease in deferred income taxes liability - long-term is due to the change in the state tax obligation changing from a liability to an asset.

The $1 million increase in the long-term portion of the asset retirement obligations from $177 million at December 31, 2023 to $178 million at March 31, 2024 was due to $3 million of accretion expense, largely offset by $2 million of liabilities settled during the period.

The $4 million increase in other noncurrent liabilities is primarily a result of the first quarter obligation for greenhouse gas allowances due in over one year.

The $69 million decrease in stockholders' equity was due to $24 million of common stock dividends, $40 million in net loss, and $5 million of shares withheld for payment of taxes on equity awards, partially offset by $1 million of stock-based compensation.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiaries, 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 any reserve balances at March 31, 2024 and December 31, 2023. 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 subsidiaries, 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 March 31, 2024, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Securities Class Action") 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 (collectively, the "Defendants"). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the "Securities Act"), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the "Exchange Act"), 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 2018 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.

On November 1, 2021, the court-appointed co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company's permits and permitting processes. The amended 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. The Defendants filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement at the hearing on February 6, 2024. On February 16, 2024, the Court entered a final settlement-approval order and judgment and terminated the case, and the settlement funds were subsequently disbursed to the class from an existing escrow account. The Defendants continue to maintain that the claims are without merit and admitted no liability in connection with the settlement. This litigation is now concluded,and the Company will no longer report on it in future filings.

On October 20, 2022, a shareholder derivative lawsuit (the “Assad Lawsuit”) was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties’ joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the “Karp Lawsuit,” together with the Assad Lawsuit, the “Shareholder Derivative Actions”) was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry’s 2022 proxy statement was false and misleading in that it suggested the Company’s internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties’ joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of March 31, 2024:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Debt obligations:					
RBL Facility	$ 51,000	$ —	$ 51,000	$ —	$ —
2026 Notes	400,000	—	400,000	—	—
Interest[1]	52,500	28,000	24,500	—	—
Deferred acquisition payable[2]	19,500	19,500	—	—	—
Other:					
Leases	8,147	3,154	3,850	1,143	—
Asset retirement obligations[3]	197,900	20,000	—	—	177,900
Off-Balance Sheet arrangements:[4]					
Transportation contracts[5]	78,387	11,233	17,543	16,165	33,446
Other purchase obligations[6]	17,100	8,400	8,700	—	—
Total contractual obligations	$ 824,534	$ 90,287	$ 505,593	$ 17,308	$ 211,346

(1) Represents interest on the 2026 Notes computed at 7% through contractual maturity in 2026.

(2) Relates to the remaining payable of $20 million, on a discounted basis, for the acquisition of Macpherson Energy, LLC due in July 2024. The remaining payable amount is subject to customary purchase price adjustments.

(3) Represents the estimated future asset retirement obligations on a discounted basis. We do not show the long-term asset retirement obligations by year as we are not able to precisely predict the timing of these amounts. Because these costs typically extend many years into the future, estimating these future costs requirement management to make estimates and judgements that are subject to revisions based on numerous factors, including the rate of inflation, changing technology, and changes to federal, state and local laws and regulations. See Note 1—Basis of Presentation in the notes to consolidated financial statements in Part II—Item 8. “Financial Statements and Supplementary Data” in our Annual Report for more information.

(4) These commitments and contractual obligations are expected to be funded by our cash flow from operations.

(5) 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 pipeline transportation of natural gas to market and between markets.

(6) As of March 31, 2024, we have a total drilling commitment in California of $17.1 million. We are required to drill 57 wells consisting of 28 wells by December 2024 and the remaining 29 wells by June 2025.

Critical Accounting Policies and Estimates

There have been no significant changes to our critical accounting policies and estimates from those disclosed on our Annual Report. See Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” in our Annual Report.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this Quarterly Report includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. 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. All statements other than statements of historical facts included in this Quarterly Report that address plans, activities, events, objectives, goals, strategies or developments that the Company expects, believes or anticipates will or may occur in the future, such as those regarding our financial position, liquidity, cash flows (including, but not limited to, Adjusted Free Cash Flow), financial and operating results, capital program and development and production plans, operations and business strategy, potential acquisition and other strategic opportunities, reserves, hedging activities, capital expenditures, return of capital, our shareholder return model and the payment of future dividends, future repurchases of stock or debt, capital investments, our ESG strategy and the initiation of new projects or business in connection therewith, recovery factors and other guidance, are forward-looking statements. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. 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 in Part I, Item 1A. “Risk Factors” in our Annual Report 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 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;
- 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 permitting, drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, GHGs or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- inflation levels and government efforts to reduce inflation, including related interest rate determinations;
- overall domestic and global political and economic trends, geopolitical risks and general economic and industry conditions, such as inflation, high interest rates, increased volatility in financial and credit markets, global supply chain disruptions and the government interventions into the financial markets and economy;
- the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions, including the ongoing conflict in Ukraine, the ongoing conflict in the Middle East, or a prolonged recession, among other factors;
- volatility of oil, natural gas and NGL prices, including as a result of political instability, armed conflicts or economic sanctions;
- 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, including due to the actions of foreign producers, importantly including OPEC+ and change in OPEC+'s production levels;
- 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;
- competition and consolidation in the oil and gas E&P industry;
- our ability to use derivative instruments to manage commodity price risk;
- 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 or acquisitions;
- drilling and production results, 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;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- risks related to acquisitions, including the risk that we may fail to successfully integrate the assets into our operations, identify risks or liabilities associated with the acquired entity, its operations or assets, or realize any anticipated benefits or growth;
- 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, floods, and epidemics or pandemics, including the effects of related public health concerns and the impact of actions that may be taken by governmental authorities and other third parties in response to a pandemic;
- 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 cyberattacks; and
- governmental actions and political conditions, as well as actions by other third parties that are beyond our control.

Any forward-looking statement speaks only as of the date on which such statement is made. Except as required by law, we undertake no responsibility to correct or update any forward-looking statements, whether as a result of new information, future events or otherwise except as required by applicable law.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As of March 31, 2024, there have been no material changes in the information required to be provided under Item 305 of Regulation S-K included in Part II, Item 7A. *"Quantitative and Qualitative Disclosures About Market Risk"* in our 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 decline.

We have historically hedged a large portion of our expected crude oil and our natural gas production, as well as our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls, puts and collars 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 and emission allowances required by California's cap-and-trade program 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 March 31, 2024, the fair value of our hedge positions was a net liability of approximately $67 million. A 10% increase in the oil and natural gas index prices above the March 31, 2024 prices would result in a net liability of approximately $153 million; conversely, a 10% decrease in the oil and natural gas index prices below the March 31, 2024 prices would result in a net asset of approximately $15 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. "Financial Statements" of this Quarterly Report.

At March 31, 2024, the fair value of our emission allowances required by California's cap-and-trade program was $6 million. A 10% increase or decrease in the market price would result in a change in expense by less than $1 million.

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 Chief Executive Officer and our Vice President, Chief Financial Officer and Chief Accounting 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 Exchange Act) 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 March 31, 2024.

The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. The Company's disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Chief Executive Officer and the Vice President, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company's internal control over financial reporting during the first quarter of 2024 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 "Securities Class Action") 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 (collectively, the "Defendants"). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the "Securities Act"), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the "Exchange Act"), 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 2018 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.

On November 1, 2021, the court-appointed co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company's permits and permitting processes. The amended 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. The Defendants filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement at the hearing on February 6, 2024. On February 16, 2024, the Court entered a final settlement-approval order and judgment and terminated the case, and the settlement funds were subsequently disbursed to the class from an existing escrow account. The Defendants continue to maintain that the claims are without merit and admitted no liability in connection with the settlement. This litigation is now concluded,and the Company will no longer report on it in future filings.

On October 20, 2022, a shareholder derivative lawsuit (the “Assad Lawsuit”) was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties’ joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the “Karp Lawsuit,” together with the Assad Lawsuit, the “Shareholder Derivative Actions”) was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry’s 2022 proxy statement was false and misleading in that it suggested the Company’s internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties’ joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

Other Matters

For additional information regarding legal proceedings, see Note 4—Commitments and Contingencies in the notes to condensed consolidated financial statements in Part I, Item 1. “Financial Statements” in this Quarterly Report and Note 5—Commitments and Contingencies in the notes to consolidated financial statements in Part II, Item 8. “Financial Statements and Supplementary Data” in our Annual Report.

Item 1A. Risk Factors

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

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

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended March 31, 2024. As of March 31, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $114 million in aggregate, which is 16% of outstanding shares as of March 31, 2024. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of March 31, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and the share repurchase program does not obligate the Company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Item 5. Other Information

(c) Trading Plans

During the three months ended March 31, 2024, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

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 to the Company's Current Report on Form 8-K filed February 19, 2020)
3.2	Fourth Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed January 31, 2023)
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 to the Company's Current Report on Form 8-K filed July 30, 2018)
4.1	First Supplemental Indenture, dated as of January 4, 2024, among Berry Petroleum Company, LLC, as issuer, Berry Corporation (bry) (f/k/a Berry Petroleum Corporation), the subsidiary guarantors party thereto and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National As-sociation), as trustee (incorporated by reference to Exhibit 4.4 of the Company's Annual Report on Form 10-K filed March 8, 2024)
4.2	Second Supplemental Indenture, dated as of February 8, 2024, among Berry Petroleum Company, LLC, as issuer, Berry Corporation (bry) (f/k/a Berry Petroleum Corporation), Macpherson Green Power Company, LLC and Computershare Trust Company, N.A. (as successor to Wells Fargo Bank, National Association), as trustee (incorporated by reference to Exhibit 4.5 of the Company's Annual Report on Form 10-K filed March 8, 2024)
10.1	Form of Restricted Stock Unit Award Agreement for Executives (2024) (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.2	Form of Restricted Stock Unit Award Agreement for Executives without Employment Agreement (2024) (incorporated by reference to Exhibit 10.28 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.3	Form of Performance-Based Restricted Stock Unit Award Agreement for Executives (Absolute TSR) (2024) (incorporated by reference to Exhibit 10.29 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.4	Form of Performance-Based Restricted Stock Unit Award Agreement for Executives without Employment Agreement (Absolute TSR) (2024) (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.5	Form of Performance-Based Restricted Stock Unit Award Agreement for Executives (Relative TSR) (2024) (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.6	Form of Performance-Based Restricted Stock Unit Award Agreement for Executives without Employment Agreement (Relative TSR) (2024) (incorporated by reference to Exhibit 10.32 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.7	Sixth Amendment to the Credit Agreement dated as of February 23, 2024, by and among Berry Petroleum Company, LLC, as borrower, Berry Corporation (bry), JPMorgan Chase Bank, N.A., as administrative agent, and each of the lenders signatory thereto (incorporated by reference to Exhibit 10.42 to the Company's Annual Report on Form 10-K filed March 8, 2024)
10.8	Second Amendment to Revolving Loan and Security Agreement and Amendment to Other Loan Documents, dated as of November 15, 2023, by and among C&J Well Services, LLC, as a borrower, CJ Berry Well Services Management, LLC, as a borrower, and Tri Counties Bank, as lender (incorporated by reference to Exhibit 10.43 to the Company's Annual Report on Form 10-K filed March 8, 2024)
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:

"*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 unusual and infrequent items.

"*Adjusted Free Cash Flow*" is a non-GAAP financial measure which is defined (i) through December 31, 2023, as cash flow from operations less regular fixed dividends and maintenance capital and (ii) beginning January 1, 2024, as cash flow from operations, less regular fixed dividends and capital expenditures. Adjusted Free Cash Flow for prior periods has not been retroactively adjusted for the updated definition.

"*Adjusted General and Administrative Expenses*" is a non-GAAP financial measure defined as general and administrative expenses adjusted for non-cash stock compensation expense and 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, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our effective tax rate.

"AROs" means asset retirement obligations.

"*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.

"*boe*" means barrel of oil equivalent, determined using the ratio of one bbl of oil, condensate or natural gas liquids to six mcf of natural gas.

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

"*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.

"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.

"CEQA" is an abbreviation for the California Environmental Quality Act which, among other things, requires certain governmental agencies to conduct environmental review of projects for which the agency is issuing a permit.

"CJWS" refers to C&J Well Services, LLC and CJ Berry Well Services Management, LLC, the two entities that constitute our upstream well servicing and abandonment business segment in California.

"*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.

"*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.

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

"*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.

"HSE" is an abbreviation for Health, Safety, and Environmental.

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

"*EPS*" is an abbreviation for earnings per share.

"*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.

"*Field*" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

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

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

"*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.

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

"*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.

"*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.

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

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

"mboe" means one thousand barrels of oil equivalent.

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

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

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

"mmboe" means one million barrels of oil equivalent.

"mmb*tu*" means one million btus.

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

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

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

"*MW*" means megawatt.

"*MWHs*" means megawatt hours.

"*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.

"*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.

"*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

"*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.

"*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.

"*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.

"*SOFR*" is an abbreviation for Secured Overnight Financing Rate.

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

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

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

"*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 CERCLA.

“*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:	May 1, 2024	*/s/* Fernando Araujo
		Fernando Araujo Chief Executive Officer (Principal Executive Officer)
Date:	May 1, 2024	*/s/* Michael S. Helm
		Michael S. Helm Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial Officer and 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, Fernando Araujo, 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: May 1, 2024

/s/ Fernando Araujo

Fernando Araujo

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, Michael S. Helm, 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: May 1, 2024

/s/ Michael S. Helm

Michael S. Helm

Vice President, Chief Financial Officer, and Chief Accounting 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 March 31, 2024, as filed with the Securities and Exchange Commission on May 1, 2024 (the “Report”), Fernando Araujo, as Chief Executive Officer of the Company, and Michael S. Helm, as Vice President, Chief Financial Officer, and Chief Accounting 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:	May 1, 2024	/s/ Fernando Araujo
		Fernando Araujo
		Chief Executive Officer
Date:	May 1, 2024	/s/ Michael S. Helm
		Michael S. Helm
		Vice President, Chief Financial Officer and Chief Accounting 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.