2023 ANNUAL REPORT

Delivering Excellence Through Ingenuity

bry
BERRY CORPORATION

LETTER FROM THE CEO

Delivering Meaningful Value to Shareholders

2023 was a year of strong execution for Berry, defined by delivering excellence through our technical and operating strengths, efficiently managing the business, and enhancing our future cash flow generation by acquiring bolt-on opportunities—already producing properties with upside potential. Guided by our company's core values, we executed on the key elements of our corporate strategy and continued to generate sustainable shareholder returns and shareholder value. In 2023, we returned a total of $65 million to shareholders in the form of dividend payments and share repurchases.

One of the top priorities for Berry in 2023 was identifying accretive, producing bolt-on opportunities, and we did, closing on two value-creating, cash flow accretive acquisitions. The Macpherson Acquisition that we closed in September 2023, and the complementary working interest acquisition we made in December 2023, have helped us maintain base production levels and will enhance our free cash flow for 2024. Both acquisitions were completed without adding to our long-term debt and will be paid off in 2024. Berry remains well positioned to be a consolidator, and we will continue to pursue acquisitions in and outside of California that will support production and increase future free cash flow and shareholder value.

In 2023, we maintained steady production partly by effectively developing and managing our reservoirs, and we did so with lower capital expenditures than budgeted. Working together, our operations, production and reservoir teams improved surveillance standards, data collection and analysis, resulting in year-over-year cost savings and evolution of reservoir strategy across our existing oil fields. For example, in two of our fields, we were able to improve our operating margins by significantly reducing steam injection with minimal impact to production. Notably, Berry was also the first operator locally to pursue sidetrack permits after new drill approvals slowed. This was done to sustain development and we rapidly evolved the process to the point where it is now a standard practice for the company.

I want to highlight one additional example that further demonstrates the strength of our assets and ingenuity of our teams. The team evaluated and discovered oil accumulations in undeveloped stacked reservoirs, deeper than our traditional targets, which are recoverable without steam. These are reservoirs that Berry had not produced from before, so our geologists and engineers are currently appraising new opportunities to maintain our production and grow our reserves. Initial production from these wells is in the low triple digits, which is higher than our average new well production from shallow reservoirs in California. This is another example of the quality of our asset base, especially in California.

I would like to acknowledge Trem Smith, who served as Berry's board chairman, president and CEO from 2017–2022, and was our board's executive chairman for the past year. Trem departed the board in March, and we are grateful for his years of service and dedication to Berry. His vision and leadership were integral to the growth of the company and helped position our organization for long-term success. I look forward to collaborating with Renée Hornbaker, who has assumed the role of Berry's new board chair.

In 2024, the priorities for Berry remain consistent. Through the proven ingenuity and creativity of our teams and the strength of our assets, we are confident in our ability to continue to execute our strategy and deliver meaningful value to shareholders. We will protect our base business by sustaining production levels, being a cost-effective producer, enhancing our capital efficiency, and being compliant and safe. We will explore growth opportunities and scale in our E&P business, as well as expansion in C&J Well Services' business. Finally, we will return capital to our shareholders through our shareholder return model and expect to invest in the business to maintain enterprise value for the long-term. We are excited about Berry's future in 2024 and beyond.

Fernando Araujo
Chief Executive Officer & Board Member

FINANCIAL PERFORMANCE

Solid Financial and Operational Results

Year-over-year, we continue to deliver solid financial and operational results, demonstrating the quality of our assets, and ability to successfully navigate through California's regulatory environment. Berry's balance sheet is strong and continues to produce steady returns for its shareholders.

In 2023, Berry generated $268 million of Adjusted EBITDA,[1] which includes $26 million of Adjusted EBITDA[1] from C&J Well Services. From these earnings, we delivered Adjusted Free Cash Flow[1] of $97 million in 2023. Our 2023 financial results provided $65 million in cash returns to our shareholders through $55 million in fixed and variable dividends and $10 million in share repurchases. For the full year, we paid total dividends of $0.73 per share, and these total cash returns resulted in a top-tier sector total dividend yield of approximately 10% for our shareholders. Net income in 2023 was $37 million and cash flows from operating activities totaled $199 million.

At year end, Berry had liquidity of $171 million, consisting of $5 million cash and $166 million available for borrowings under the company's revolving credit facilities.

Throughout 2023, we had a sharp focus on executing initiatives to lower our costs. 2023 operating expenses on a boe basis were lower than our guidance, and G&A was lower, including Adjusted G&A,[1] which was approximately 4% lower than 2022. Looking ahead to 2024, we will remain highly focused on managing the operational and financial variables within our control. In 2024, we plan to further reduce Adjusted G&A[1] by 6% year-over-year and continue to explore ways to achieve savings on our operating expenses.

SHAREHOLDER RETURN MODEL

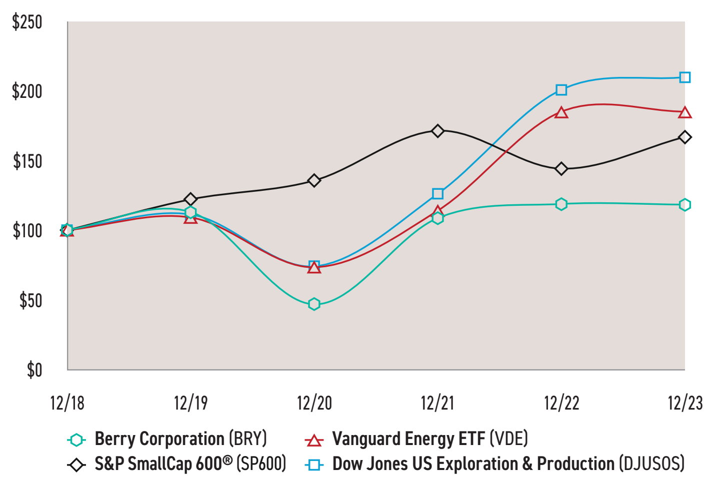
Berry's shareholder return model in 2023 was based on annual Adjusted Free Cash Flow,[1] calculated after the payment of the fixed dividend, 20% of which was earmarked for variable dividends. The remaining 80% was intended for opportunistic debt and stock repurchases, as well as for strategic growth and the acquisition of producing bolt-ons.

In 2023, Adjusted Free Cash Flow[1] was $97 million, after the payment of $36 million in fixed dividends ($0.48 per share). Berry paid out $19 million in variable dividends, or 20% of Adjusted Free Cash Flow,[1] for total 2023 dividend payments of $55 million ($0.73 per share). Additionally, in the second quarter of 2023, Berry made $10 million in share repurchases, and non-E&P capital (for both C&J Well Services and Berry) and other acquisitions accounted for an additional $17 million. Finally, the majority of Adjusted Free Cash Flow,[1] $51 million, was used for the Macpherson Acquisition, which closed at the end of the third quarter in 2023.

Looking ahead, Berry is well positioned to continue to deliver healthy Adjusted Free Cash Flow,[1] and steady shareholder returns.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN*

Among Berry Corporation, Vanguard Energy ETF, the S&P SmallCap 600® Index and the Dow Jones US Exploration & Production Index



**$100 invested on December 31, 2018 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.*

1. See ir.bry.com for a discussion of these performance and non-GAAP measures, including a reconciliation to the nearest comparable GAAP measure.


Weatherford
Maximizer III Pumping Unit
SIGR

OPERATIONAL PERFORMANCE

Optimizing Our Production

In 2023, Berry produced 25,400 boe/day. Berry replaced 176% of our California production with additional proved reserves from field extensions and acquisitions, which more than offset the impact of 2023 company-wide production and lower commodity pricing. Berry maintains a large inventory portfolio with a proved reserves-to-production (R/P) ratio of approximately 11 years.

Our 2023 production results demonstrate our ability to leverage our base optimization efforts. We continued to improve recoveries and efficiencies in our thermal diatomite reservoirs, which have seen year-over-year new peak performance (without drilling any new wells) driven by our enhanced understanding of reservoir dynamics and subsequent revised operating strategy. Improved surveillance standards, data collection and analysis have also resulted in year-over-year cost savings across all reservoirs.

Other production optimization highlights include:

- Significantly reduced steam injection through optimization with minimal impact to production, improving operating margins at two fields.
- Successful execution of two wells to deeper formations (new to Berry) with primary production demonstrating rates that have the potential to support commercial development.

Berry continues to rise to the challenge of a dynamic regulatory environment. In 2023, after new drill permits paused, Berry was the first operator locally to pursue sidetrack permits to sustain development activity, now considered standard operation for the company.

On the operations front, following through on our commitment to the safety of our employees and contractors, Berry experienced a near-perfect safety year in 2023, highlighted by zero lost time incidents. Additionally, through Cogen and water optimization efforts we were able to maximize value from our operations at our Homebase properties in Kern County.

"Berry experienced a near-perfect safety year in 2023, highlighted by zero lost time incidents."

Our People Are Our Most Prized Asset

Following our succession plan for our executive leadership team that was announced in late 2022, in 2023, Berry initiated and completed the succession planning process for several critical positions within the company. This ensures that we have in place a capable leadership pipeline for years to come.

At Berry we believe that our people are the strongest drivers of our company's success, and in 2023, continued to make critical investments in our employees with the creation of additional development programs. In coordination with foremen from both our California and Utah operations, we launched a competency development program for field operators to enhance their skills and expertise and further elevate their capabilities to enable them to remain leaders in their roles. We also introduced a tailored training program specifically for new recruits in entry-level field operator positions. The goal of this program is to equip these employees with the necessary resources and knowledge to help establish a strong foundation for future growth within Berry. For our geologists, we were also excited to create a competency development program for them in collaboration with their team and team leaders. The launch and successful execution of these programs signifies our unwavering commitment to the support and development of one of our most valuable assets—our people.

COMMUNITY ENGAGEMENT

Berry's ongoing commitment to the communities where we operate and where our employees work and live is driven by one of our company's Core Values: "Responsible."

Berry supports communities through engagement, direct funding, and employee participation and volunteering. We know our employees play a vital role in taking care of our communities, and in keeping with our commitment to empower employees, Berry has an employee match program in place for employees who financially contribute to local organizations, thereby maximizing the individual and collective effort.

Currently, there are 95 organizations that have been pre-approved for employee donation matching and/or opportunities for employees to utilize volunteer paid time off hours. Berry annually provides 32 volunteer paid time off hours for its full-time employees.

In 2023, Berry was proud to continue its investment in the local communities. With contributions of just over $115,000, Berry charitable giving across operational areas increased from 2022 levels. Berry financially supported 35 organizations, and regularly participated in events, fundraisers, and community-supportive events, such as local economic development meetings and conferences.

In 2023, we were pleased to make our second "Berry Impact Giving" or B.I.G. donation. Berry pledged a total of $75,000 ($25,000 each year for the next three years) to the West Side Recreation and Park District and the Taft Fox Theater to invest in their ASPIRE program which helps develop home-grown, future leaders in the Taft, CA community and beyond.

Berry Corporation pledged $75,000 to the West Side Recreation and Park District and the Taft Fox Theater.

"The launch and successful execution of these programs signifies our unwavering commitment to the support and development of one of our most valuable assets—our people."

Berry is committed to conducting our operations in a manner that maintains, protects, and preserves our natural resources, and promotes a safe and healthy workplace. We believe this will contribute to our continued business success through enhanced job productivity, decreased costs, and improved work quality and employee satisfaction.

Providing Clean, Affordable and Reliable Energy

California oil is extracted under some of the strictest and safest standards in the world, and Berry is proud to produce this critical resource, while supporting a clean environment and protecting natural resources.

IDLE & ORPHAN WELLS

Methane emissions linked to orphan and long-term idle wells can produce much greater warming power than carbon dioxide, and improperly plugged wells can be a potential source of groundwater contamination. With C&J Well Services, Berry is well-positioned and committed to helping California safely plug and abandon other operators' idle wells, as well as those that have been orphaned throughout the state.

- In 2023, CJWS plugged just over 2,000 wells for California operators.

ADDITIONAL SUSTAINABILITY HIGHLIGHTS

- In 2023, Berry completed construction of a solar project at the company's Hill property, which reduces the electricity we are required to purchase, and lowers our Scope 2 emissions.
- In 2023 CJWS purchased approximately $4 million in final Tier 4 engines, which significantly reduced two key pollutants: particulate matter (PM) and nitrogen oxides (NOx).
- CJWS has transitioned all its equipment to use renewable diesel fuel (RD99).

"...Berry is well-positioned and committed to helping California safely plug and abandon other operators' idle wells, as well as those that have been orphaned throughout the state."

The Core Values That Define Berry

STRONGER TOGETHER

BREED EXCELLENCE

RESPONSIBLE

DO THE RIGHT THING

OWN IT

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2023

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was $449.8 million.

Shares of common stock outstanding as of February 29, 2024:	76,333,111

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held May 23, 2024) will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2023 and is incorporated by reference in Part III to the extent described herein.

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

Part I

Items 1 and 2. Business and Properties

"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"), (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"). 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. As of September 15, 2023, Berry LLC also owns Macpherson Energy, LLC (formerly known as Macpherson Energy Corporation) and its subsidiaries ("Macpherson Energy").

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.

In September 2023, we completed the acquisition of Macpherson Energy (the "Macpherson Acquisition"), a privately held Kern County, California operator. The Macpherson Energy assets are high-quality, low decline oil producing properties that are closely located to existing Berry properties in rural Kern County, California. In December 2023, we acquired additional, highly synergistic working interests in Kern County, California. These assets align with our strategy of acquiring accretive, producing bolt-ons in support of our goal to maintain flat production year-over-year.

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 shareholder value through overall returns. Since our initial public offering in July 2018 ("IPO"), we have demonstrated our commitment to maximizing shareholder value and returning a substantial amount of 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 went into effect January 1, 2022, and we most recently updated the allocations at the beginning of 2023. Specifically, in 2023, the annual cumulative allocation of Adjusted Free Cash Flow was initially set at (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. Our Adjusted Free Cash Flow in 2023 was $97 million, of which $19 million, or approximately 20%, was used to pay variable cash dividends, $10 million was used for share repurchases, $51 million was used for bolt-on acquisitions, most notably the Macpherson Acquisition, and the remaining $17 million was used for other acquisitions and non-E&P capital. In 2023, after giving effect to the dividends declared for the fourth quarter of 2023 in March 2024, we will have returned directly to shareholders a total of $65 million which consisted of: (i) $19 million for the variable cash dividends, (ii) $36 million for fixed cash dividends and (iii) $10 million for share repurchases.

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. 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, 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 have updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and capital expenditures. For 2022 and 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 shareholder 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 "Regulatory Matters

—Regulation of the Oil and Gas Industry.” Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safer, more efficient and lower emission operations.

The Berry Advantage

The core of our strategy is to generate sustainable free cash flow in excess of our operating costs, while optimizing capital efficiency and our cost structure, with operational safety and compliance as a top priority. We have clear competitive advantages that have contributed, and that we believe will continue to contribute, to the execution of our business strategy. 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. We also strive to maintain an appropriate liquidity position and a manageable leverage profile that will enable us to explore attractive growth opportunities through commodity price cycles, both organically and through strategic acquisition opportunities.

- ***Stable, long-lived, oil-weighted conventional asset base with low and predictable production decline rates.*** Almost all of our interests are in properties that have produced oil and gas for decades. As a result, most of the geology and reservoir characteristics are well understood, and development well results are generally predictable and repeatable, thereby presenting lower risk than unconventional resource plays. Our properties are characterized by long-lived reserves with low production decline rates, a stable development cost structure and low-geologic risk developmental drilling opportunities with predictable production profiles. We currently have an annual corporate decline rate averaging 11-14%. We have also consistently maintained a significant inventory of new drill, sidetrack and workover opportunities that has allowed us to offset our natural decline rate and help keep production essentially flat year after year, assuming we receive permits for development activity timely. In California, our base production from existing wells requires limited maintenance capital to continue to produce. The remaining production comes from a mixture of drilling new wells and sidetracks, the workover of existing wells and occasionally from the acquisition of producing bolt-on properties. In 2023, our base production accounted for 95% of our total production. The nature of our assets also provides us with significant capital flexibility and an ability to efficiently hedge material quantities of future expected production.

- ***Extensive inventory of low geological risk drilling opportunities with attractive full-cycle economics, high operational control and capital flexibility.*** Historically, we have been able to generate attractive rates of return and positive free cash flow through typical commodity price cycles. For example, our proved undeveloped (“PUD”) reserves in California are projected to average single-well rates of return of approximately 100% based on the assumptions prepared by DeGolyer and MacNaughton in our SEC reserves report as of December 31, 2023. In addition, we currently operate approximately 98% of our producing wells, and we expect this level of operational efficiency to continue for our identified gross drilling locations. A substantial majority of our acreage is currently held by production or as fee interest, including 91% of our acreage in California. Our high degree of control over our properties gives us flexibility in executing our development program, including the timing, amount and allocation of capital expenditures, technological enhancements and marketing of our production. Furthermore, unlike many of our peers who operate primarily in unconventional plays, the equipment necessary for the development and production of our assets is generally more standardized and available, which provides us with a degree of protection against service cost inflation pressures. Our high operational control and extensive inventory of low geological risk drilling opportunities with attractive full-cycle economics enables us to quickly pivot our capital allocation between new drills and sidetracks and workovers in response to regulatory delays or other factors, providing further stability in an uncertain market and regulatory environment, and generating significant cash flow through typical commodity price cycles.

- ***Appropriate liquidity and minimal contractual obligations.*** As of December 31, 2023, we had $171 million of liquidity, consisting of $5 million of cash and $166 million available for borrowings under our revolving credit facilities. In addition, we have minimal long-term service and purchase commitments in both segments of our business, contributing to stable revenues to service debt. We also have fixed-volume delivery commitments for which we will purchase the gas needed for operations at market rates, contributing to stable expenses. This liquidity and flexibility permit us to capitalize on opportunities that may arise to make strategic acquisitions, as we did with the bolt-on acquisitions in 2023. Using strong cash flows from production, we paid down our RBL balance related to the third-quarter Macpherson acquisition early in the fourth quarter. We then utilized approximately $30 million of our RBL at year end to fund our second bolt-on.

- ***Premium commodity markets***. Oil and gas in the western United States tend to trade at a premium to other U.S. markets. The majority of our revenues are driven by California oil prices that are favorably Brent-influenced. California refiners import approximately 75% of the state's demand from OPEC+ countries and other waterborne sources, and as a result there is a closer correlation of price in California to Brent pricing than to WTI. We believe that receiving Brent-influenced pricing contributes to our ability to continue realizing strong cash margins in California.

- ***Experienced, proven, principled and disciplined management team.*** Our management team has significant experience operating and managing oil and gas businesses across numerous domestic and international basins, as well as reservoir and recovery types. We use our technical, operational and strategic management experience to optimize the value of our assets and the Company. We are committed to operating within positive free cash flow and maintaining a manageable leverage profile, while exploring attractive organic and strategic growth opportunities through commodity price cycles, and working to maintain our production levels year over year and improve the value of our reserves. In doing so, our management team takes a disciplined approach to development and operating cost management, field development efficiencies and the application of proven technologies and processes to our properties in order to generate a sustained life-cycle cost advantage.

Our Business Strategies

The principal elements of our business strategies include the following:

- ***Create value by generating significant sustainable free cash flow in excess of operating costs and optimize our returns to shareholders. We execute our strategy by investing in our business to maintain long-term value and by achieving operational excellence, focus on capital efficiency and aim to be the most cost-efficient producer, to keep production essentially flat, and to continue to be compliant and safe. Additionally, we seek to maintain balance sheet strength and flexibility through commodity price cycles.*** 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 keep production essentially flat year-over-year, generate free cash flow in excess of our operating costs and optimize returns to shareholders. Complementing this strategy, management is focused on cost reduction initiatives across the Company, while maintaining our health, safety and environmental ("HSE") standards. We also strive to maintain a manageable leverage profile and a long-term, through-cycle Leverage Ratio between 1.0x and 1.5x, or lower.

- ***Evaluate and strategically pursue acquisition opportunities.*** We seek to acquire oil and gas properties that complement our operations, provide development opportunities to enhance production, meet our accretion criteria and enhance our cash flows. Our capital flexibility supports this objective, as exemplified by the Macpherson Acquisition. We have historically pursued, and continue to pursue, bolt-on acquisitions that support our goal to maintain or moderately grow our existing production volumes in the current E&P regulatory environment, improve our capital efficiency and realize operational and corporate synergies. We believe our extensive basin-wide experience and relationships give us a competitive advantage in locating strategic acquisition opportunities in areas where we have operational and technical expertise to expand and strengthen our position in existing or nearby basins. We are also exploring opportunities to grow our market share in the California well servicing and abandonment industry. According to CalGEM, California has approximately 34,000 idle wells which will require testing, repair or plugging, including more than 5,300 deserted and orphaned wells which will be either remediated or plugged.

- ***Maximize ultimate hydrocarbon recovery from our assets by optimizing drilling, completion and production techniques and investigating reservoirs and areas beyond our known productive areas.*** While we continue to utilize proven techniques and technologies, we also continuously seek greater efficiencies in our drilling, completion and production techniques in order to optimize ultimate resource recoveries, rates of return and cash flows. We intend to continue to advance and use innovative oil recovery and other recovery techniques to unlock additional value and to allocate capital towards these next generation technologies that we believe will be accretive to our operations. In addition, we intend to take advantage of underdevelopment in basins where we operate by expanding our geologic investigation of reservoirs on our acreage and adjacent acreage below existing producing reservoirs. Through these studies, we will seek to expand our development beyond our known productive areas in order to add probable and possible reserves to our inventory at attractive all-in costs. We strive to optimize our production and grow our reserves by leveraging the expertise of our people to find or create new opportunities within our robust assets.

- ***Enhance future cash flow stability and visibility through an active and continuous hedging program.*** Our hedging strategy is designed to insulate our capital program from price fluctuations by securing price realizations and cash flows for production. We use commodity pricing outlooks and our understanding of market fundamentals to better protect our cash flows; we hedge crude oil and gas production to protect against oil and gas price decreases, and we hedge gas purchases to protect our operating expenses against price increases. We also seek to protect our operating expenses through fixed-price gas purchase agreements and pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California, which helps reduce our exposure to fuel gas purchase price fluctuations. We review our hedging program continuously as market conditions change and make our hedging decisions using a wide range of market data and analysis, while satisfying the oil hedging requirements of our revolving credit facility.

- ***Actively and collaboratively engage in matters related to regulation, HSE matters, and community relations.*** We seek to work with regulators and legislators throughout the rule-making process in an effort to minimize the adverse impacts that new legislation and regulations might have on our ability to maximize our resources. We believe that running our operations in a manner that protects the safety and health of the communities we serve and the greater environment is the right way to run our business and maintain credibility with the agencies that regulate our operations. With ultimate oversight by our Board of Directors, HSE considerations are an integral part of our day-to-day operations and are incorporated into the strategic decision-making process across our business. We strive to conduct our operations in an ethical, safe and responsible manner that safeguards the communities and the environment, and complies with existing laws and regulations. We will continue to 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, is a part of our short-term incentive program for all employees.

- ***Responsibly manage our business in a way that mitigates risk and maximizes opportunity.*** Berry is a proud energy partner and producer. We believe we play an important role in providing ample, safe, reliable, and affordable energy, while responsibly managing our operations to mitigate potential environmental impacts. The majority of our operations are in California, where we operate under some of the most rigorous and stringent environmental, health, safety, and climate requirements in the world. We seek to apply those same standards across our operations where we can and where practical for our assets and the geographies in which they are located. We take seriously our responsibility as environmental stewards, and our approach to sustainability is inextricably linked to our commitment to be a best-in-class operator—for our shareholders, stakeholders, and the natural resources on which we depend—in a way that seeks to mitigate risks and maximize opportunities to add value. We strive to continuously improve the ways in which we operate by investing in economical solutions and embracing practices that generate results.

Critical to meeting our goals to be a responsible and sustainable energy producer is maintaining a safe and healthy working environment and a culture of empowerment for our employees. We are proud to support local economies, and we seek to support the people and communities where we live and work, while delivering the energy that they need in their daily lives.

Our Capital Program

For the years ended December 31, 2023 and 2022, our total capital expenditures were approximately $73 million and $153 million, respectively, including capitalized overhead and interest and excluding acquisitions and asset retirement spending. E&P and corporate expenditures were $67 million in 2023 (excluding well servicing and abandonment capital of $6 million) compared to $145 million in 2022. Approximately 90% and 10% of these capital expenditures for the year ended December 31, 2023 was directed to California and Utah operations, respectively. In connection with the closing of the Macpherson Acquisition in September 2023, a total of $35 million was reallocated from the 2023 capital expenditures budget to fund a portion of the purchase price. The capital budget was adjusted to reflect the reduced need for drilling activities on the legacy Berry assets due to the addition of producing assets, allowing Berry to meet production targets while reducing drilling, workover and other activities on the legacy Berry assets. In 2023, we drilled five new wells and 28 new sidetracks in California and no new wells in Utah.

Our 2024 capital expenditure budget for E&P operations, CJWS and corporate activities is between $95 to $110 million, which we expect will result in 2024 production to be essentially flat to 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, workovers and other activities related to existing wellbores. We also expect to benefit from a full year of production from the assets acquired in the Macpherson Acquisition and other bolt-on acquisitions at the end of 2023, which should help keep our production essentially flat in 2024. 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, we are prepared to re-evaluate our 2024 program if we begin to receive additional new drill permits in California, including expanding the 2024 drilling program contemplated under our capital budget. Please see "—Regulatory Matters" 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 2023, we spent approximately $18 million on plugging and abandonment activities, most of which was spent to meet our annual obligations under California idle well management program. In 2024, we currently expect to spend approximately $21 million to $24 million for such activities and we again plan to meet our annual plugging and abandonment obligations in keeping with our commitments to be a responsible operator.

For information about the potential risks related to our capital program, see "Item 1A. Risk Factors," as well as "—Regulatory Matters."

Our Areas of Operation - E&P

Our E&P assets are located in the Western U.S., specifically in California and Utah, and 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).

California

California oil fields, including those in Kern County and the San Joaquin Basin, where our fields are located, are some of most resource-rich in the world. According to the U.S. Energy Information Administration, the San Joaquin basin in Kern County, California contained three of the 20 largest oil fields in the United States based on proved reserves. We have operations in two of those three fields —Midway-Sunset and South Belridge. All of our California operations are in the San Joaquin basin and rural Kern County with low population density. We believe there are extensive existing field redevelopment opportunities in and around our areas of operation within the San Joaquin basin, which also include the McKittrick, Poso Creek and Round Mountain properties. We also believe that our extensive experience in California will allow us to take advantage of these opportunities. Commercial petroleum development began in the San Joaquin basin in the late 1860s when asphalt deposits were mined and shallow wells were hand dug and drilled. Rapid discovery of many of the largest oil accumulations followed during the next several decades. Operations on our properties began in 1909. In the 1960s, introduction of thermal techniques resulted in substantial new additions to reserves in heavy oil fields. The San Joaquin basin contains multiple stacked benches that have allowed continuing discoveries of stratigraphic, structural and non-structural traps. Most oil accumulations discovered in the San Joaquin basin occurred in the Eocene age through Pleistocene age sedimentary sections. Organic rich shales from the Monterey, Kreyenhagen and Tumey formations form the source rocks that generate the oil for these accumulations.

We currently hold approximately 20,000 net acres in the San Joaquin basin in Kern County, of which 91% is held by production and fee interest. Approximately 16% of our California acres are on federal lands administered by the Bureau of Land Management ("BLM"), of which 97% is held by production. We have a 95% average working interest in our California assets, and our producing areas include:

- California operations consist of:

    - (i) our North Midway-Sunset sandstone properties, where we use cyclic and continuous steam injection to develop these known reservoirs; and our McKittrick property, which is a newer steamflood development with potential for infill and extension drilling. Also located here are our North Midway-Sunset thermal diatomite properties, which require high pressure cyclic steam techniques to unlock the significant value we believe is there and maximize recoveries.

      In response to the terms of the November 2019 moratorium on approval of new high-pressure cyclic steam wells, Berry has applied to CalGEM to resume high-pressure cyclic steam operations in this area via a revised Underground Injection Control ("UIC") program to support our future development plans. Berry proposes to do so under terms and conditions we believe are in accordance with the results of the study co-led by Lawrence Livermore National Laboratory and CalGEM, which recommended strategies for avoidance of surface expressions experienced by certain operators prior to the 2019 moratorium. In the meantime, we have approved sidetrack permits for redevelopment which we intend to develop in 2024. Please see "—Regulation of Health, Safety and Environmental Matters—Additional CalGEM Actions on Oil and Gas Activities" for more information;

    - (ii) our South Midway-Sunset, properties, which are long-life, low-decline, strong-margin thermal oil properties with additional development opportunities;

- (iii) our South Belridge Field Hill property, which is characterized by two known reservoirs with low geological risk containing a significant number of drilling prospects, including downspacing opportunities, as well as additional steamflood opportunities;
- (iv) our Poso Creek property, which is an active mature shallow, heavy oil asset that we continue to develop. We develop these sandstone properties with a combination of cyclic and continuous steam injections, similar to many of our west California operations; and
- (v) our Round Mountain property, which we recently acquired as part of the Macpherson Acquisition. This property has two productive sandstone reservoirs that are developed using waterflood and steamflood.

Our California proved reserves represented approximately 87% of our total proved reserves at December 31, 2023. California accounted for 20.7 mboe/d, or 81%, of our average daily production for the year ended December 31, 2023.

Along with these upstream operations, we have infrastructure and excess available takeaway capacity in place to support additional development in California. We produce oil from heavy crude reservoirs using steam to heat the oil so that it will flow to the wellbore for production. To help support this operation, we own and operate four natural gas-fired cogeneration plants that produce electricity and steam. These plants, in the Midway-Sunset and McKittrick fields, supply approximately 10% of our steam needs and approximately 43% of our field electricity needs to power our operations in California, on average generally at a discount to electricity market prices. The lower steam and electricity contributions compared to prior year was due to economic decisions made on when to run the cogeneration plants. To further help offset our costs, we also sell electricity produced by two of our cogeneration facilities under long-term contracts with terms ending in December 2024 and November 2026. We also own 59 conventional steam generators to help satisfy the steam required by our operations.

In addition, we own gathering, storage, treatment, water recycling and softening facilities, reducing our need to spend capital to develop nearby assets and generally allowing us to control certain operating costs. Approximately 92% of our California oil production is sold through pipeline connections, however, we can also sell our oil using trucking during short-term pipeline market disruptions.

Uinta Basin, Utah

The Uinta basin is a mature, light-oil-prone play covering more than 15,000 square miles with significant undeveloped resources where we have high operational control and additional behind pipe potential. Our Uinta basin operations in the Brundage Canyon, Ashley Forest, Lake Canyon and Antelope Creek areas in Utah target the Green River and Wasatch formations that 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, which provides significant upside for additional vertical and or horizontal development and recompletions. We currently hold approximately 99,000 net acres in the Uinta basin, of which 91% is held by production. Approximately 26% of our Utah acreage is on federal lands administered by the BLM, of which 71% is held by production. Approximately 67% of our Utah acreage is on tribal lands, of which 98% is held by production.

Our Uinta basin proved reserves represented approximately 13% of our total proved reserves at December 31, 2023 and accounted for 4.7 mboe/d or 19% of our average daily production for the year ended December 31, 2023.

We also have extensive gas infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. We have natural gas gathering systems consisting of approximately 500 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. We also own a natural gas processing plant in the Brundage Canyon area located in Duchesne County, Utah with capacity of approximately 30 mmcf/d. This facility takes delivery from gathering and compression facilities we operate. Approximately 88% of the gas gathered at these facilities is produced from wells that we operate. Current throughput at the processing plant is 11-15 mmcf/d and sufficient capacity remains for additional large-scale development drilling.

Formed during the late Cretaceous to Eocene periods, the Uinta basin is a mature, light-oil-prone play located primarily in Duchesne and Uintah Counties of Utah and covers more than 15,000 square miles. Exploration efforts immediately after the Second World War led to the first commercial oil discoveries in the Uinta basin. Oil was discovered in, and produced from, fluvial to lacustrine sandstones of the Green River formation in these early discoveries. The application of improved hydraulic stimulation techniques in the mid-2000s greatly increased production from the Uinta basin. As reported by the Utah Department of Natural Resources, total Utah oil production more than tripled from 36 mbbl/d in 2003 to 120 mbbl/d as of October 2023. Approximately 90% of Utah's oil production as of October 2023 came from the Uinta basin in Duchesne and Uintah counties.

Our Well Servicing and Abandonment Business

C&J, our well servicing and abandonment segment, operates one of the largest upstream well servicing and abandonment businesses in California. 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 is a strategic growth opportunity for Berry based on the significant market of orphaned, deserted and idle wells within California. C&J is a synergistic fit with the services required by our oil and gas operations and supports our commitment to be a responsible operator and reduce our emissions, including through the proactive plugging and abandonment of wells. Additionally, C&J is critical to advancing our strategy to work with the State of California to reduce fugitive emissions—including methane and carbon dioxide—from orphaned idle wells, as California utilizes newly available state and federal funds to remediate these wells. According to CalGEM, there are approximately 34,000 idle wells estimated to be in California, including more than 5,300 deserted and orphaned wells. With C&J's expertise and experience in well abandonment, we have an opportunity to help remediate orphaned idle wells that are a burden on the State of California, in addition to safely plugging and abandoning idle wells for C&J's customers.

In 2023, C&J operated an average fleet of 71 well servicing rigs, also commonly referred to as workover rigs, and related equipment. These services are performed to establish, maintain and improve production throughout the productive life of an oil and natural gas well and to plug and abandon a well at the end of its productive life. Our well servicing business performs various services to establish, maintain and improve production throughout the productive life of an oil and natural gas well, which include:

- Maintenance work involving removal, repair and replacement of down-hole equipment and components, and returning the well to production after these operations are completed;
- Well workovers which potentially include deepening, sidetracks, adding productive zones, isolating intervals, repairing casings required by the operation into and out of the well, or removing equipment from the wellbore; and
- Plugging and abandonment services when a well has reached the end of its productive life.

Regular maintenance is required throughout the life of a well to sustain optimal levels of oil and natural gas production. Regular maintenance currently comprises the largest portion of our well services work, and because ongoing maintenance spending is required to sustain production, we have historically experienced relatively stable demand for these services.

In addition to periodic maintenance, producing oil and natural gas wells occasionally require major repairs or modifications called workovers, which are typically more complex and more time consuming than maintenance operations. The demand for workover services is sensitive to oil and natural gas producers' intermediate and long-term expectations for oil and natural gas prices. As oil and natural gas prices increase, the level of workover activity tends to increase as oil and natural gas producers seek to increase output by enhancing the efficiency of their wells.

Well servicing rigs are also used in the process of permanently closing oil and natural gas wells no longer capable of producing in economic quantities. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and natural gas prices than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive.

Our water logistics business utilizes our fleet of 214 water logistics trucks and related assets, including specialized tank trucks, storage tanks and other related equipment. These assets provide, transport, and store a variety of fluids, as well as provide maintenance services. These services are required in most workover and remedial projects and are routinely used in daily producing well operations. We also have approximately 1,360 pieces of rental equipment on our water logistics side.

Our Assets and Production Information

For the year ended December 31, 2023, we had average net production of approximately 25.4 mboe/d, of which approximately 93% was oil and approximately 81% was in California. In California, our average production for the year ended December 31, 2023 was 20.7 mboe/d, of which 100% was oil. We divested all of our properties in the Piceance basin of Colorado in January 2022.

The table below summarizes our average net daily production for the years ended December 31, 2023, 2022 and 2021:

	Average Net Daily Production[(1)] for the Year Ended December 31,					
	2023		2022		2021	
	(mboe/d)	Oil (%)	(mboe/d)	Oil (%)	(mboe/d)	Oil (%)
California[(2)]	20.7	100 %	21.3	100 %	22.0	100 %
Utah[(3)]	4.7	59 %	4.7	58 %	4.2	51 %
	25.4	93 %	26.0	92 %	26.2	88 %
Colorado[(4)]	—	— %	0.1	— %	1.2	2 %
Total	25.4	93 %	26.1	92 %	27.4	88 %

(1) Production represents volumes sold during the period.

(2) Includes production for Placerita properties through the end of October 2021 when they were divested. These properties had average daily production in 2021 of approximately 0.7 mboe/d. Production for the year ended December 31, 2023 included 0.5 mboe/d for the Round Mountain area which was acquired in September 2023.

(3) Includes production for Antelope Creek area from February 2022, when it was acquired, through December 31, 2023. These assets contributed production of approximately 1.1 mboe/d for 2023 and 1.0 mboe/d for 2022.

(4) Our properties in Colorado were in the Piceance basin, all of which were divested in January 2022.

Production Data

The following table sets forth information regarding production for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
	2023	2022	2021
Average daily production[1]:			
Oil (mbbl/d)	23.5	24.0	24.2
Natural gas (mmcf/d)[3]	8.8	10.2	17.1
NGLs (mbbl/d)	0.4	0.4	0.4
Total (mboe/d)[2][3]	25.4	26.1	27.4

(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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu, respectively.

(3) In January 2022, we divested our Piceance basin properties which produced natural gas.

Our Development Inventory

We have an extensive inventory of low-geologic risk, high-return development opportunities. As of December 31, 2023, we identified 9,216 proven and unproven gross drilling locations across our asset base. For a discussion of how we identify drilling locations, please see "—Our Reserves—Determination of Identified Drilling Locations."

We have an average working interest of approximately 96% of our producing wells. In addition, a substantial majority of our acreage is currently held by production and fee interest, including 91% of our acreage in California. As of December 31, 2023, the combined net acreage covered by leases expiring in the next three years represented approximately 3% of our total net acreage, of which 50% is in Utah. Our high degree of operational control, together with the large portion of our acreage that is held by production, and the speed with which we are able to drill and complete our wells in California gives us flexibility over the execution of our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production. Despite our high degree of operational control and flexibility, ongoing permitting issues may prevent us from being able to execute on the development program as planned.

The following table summarizes certain information concerning our active producing and identified development assets as of December 31, 2023:

	Acreage		Net Acreage Held By Production and Fee Interest(%)	Producing Wells, Gross[3]	Average Working Interest (%)[4]	Net Revenue Interest (%)[5]	Identified Drilling Locations[6]	
	Gross	Net[1][2]					Gross	Net
California	24,877	19,895	91 %	2,731	95 %	95 %	7,827	7,816
Utah	110,010	99,349	91 %	1,250	96 %	78 %	1,389	1,389
Total	134,887	119,244	91 %	3,981	96 %	88 %	9,216	9,205

(1) Represents our weighted-average interest in our acreage.

(2) Of which approximately 16% are BLM acres in California and 26% are BLM acres in Utah.

(3) Includes 584 steamflood and waterflood injection wells in California and Utah.

(4) Represents our weighted-average working interest in our active wells.

(5) Represents our weighted-average net revenue interest for the year ended December 31, 2023.

(6) Our total identified drilling locations include approximately 701 gross (696 net) locations associated with PUDs as of December 31, 2023, including 164 gross (163 net) steamflood and waterflood injection wells. Please see "—Our Reserves—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations.

Our Reserves

Reserve Data

As of December 31, 2023, we had estimated total proved reserves of 103 mmboe, compared to 110 mmboe as of December 31, 2022. Our overall proved reserves increased two mmboe, or 2% in 2023, before production of nine mmboe, largely due to the Macpherson Acquisition and extensions in our California properties, partially offset by revisions of previous estimates.

The majority of our reserves are composed of crude oil in shallow, long-lived reservoirs. As of December 31, 2023, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately $1.7 billion and $2.0 billion, respectively, compared to December 31, 2022 of $2.1 billion and $2.6 billion. The decrease in PV-10 is largely due to a decrease in commodity pricing based on the SEC method of calculating price for provided reserves. PV-10 is a financial measure that is not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see in "—PV-10" below. As of December 31, 2023, approximately 87% of our proved reserves and approximately 97% of the PV-10 value of our proved reserves are derived from our assets in California. We also have approximately 13% of our proved reserves and approximately 3% of the PV-10 value in the Uinta basin in Utah, a mature, light-oil-prone play with significant undeveloped resources.

The tables below summarize our estimated proved reserves and related PV-10 by category as of December 31, 2023:

	Proved Reserves as of December 31, 2023[(1)]							
	Oil (mmbbl)	Natural Gas (bcf)	NGLs (mmbbl)	Total (mmboe)[(2)]	% of Proved	% Proved Developed	Capex[(3)] ($MM)	PV-10[(4)] ($MM)
PDP	46	18	1	50	48 %	88 %	32	1,032
PDNP	6	3	—	7	7 %	12 %	62	129
PUD	46	5	—	46	45 %	— %	464	888
Berry total proved reserves	98	26	1	103	100 %	100 %	558	2,049
California total proved reserves	90	—	—	90			450	1,977

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $82.84 per bbl Brent for oil and natural gas liquids ("NGLs") and $2.63 per mmbtu Henry Hub for natural gas at December 31, 2023. The volume-weighted average realized prices over the lives of the properties were estimated at $77.30 per bbl of oil and condensate, $26.90 per bbl of NGLs and $3.73 per mcf of gas. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules, including adjustment by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Please see "—Our Reserves—PV-10" below.

(2) Estimated using a conversion ratio of six mcf of natural gas to one bbl of oil.

(3) Represents undiscounted future capital expenditures estimated as of December 31, 2023.

(4) PV-10 is a financial measure that is not calculated in accordance with GAAP. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—Our Reserves—PV-10" below. PV-10 does not give effect to derivatives transactions.

The following table summarizes our estimated proved reserves and related PV-10 by area as of December 31, 2023. The reserve estimates presented in the table below are based on reports prepared by DeGolyer and MacNaughton. The reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting. Reserves are stated net of applicable royalties.

	Proved Reserves as of December 31, 2023[1]		
	California (San Joaquin basin)	Utah (Uinta basin)	Total
Proved developed reserves:			
Oil (mmbbl)	46	6	52
Natural gas (bcf)	—	21	21
NGLs (mmbbl)	—	1	1
Total (mmboe)[2][3]	46	11	57
Proved undeveloped reserves:			
Oil (mmbbl)	44	2	46
Natural gas (bcf)	—	5	5
NGLs (mmbbl)	—	—	—
Total (mmboe)[3]	44	2	46
Total proved reserves:			
Oil (mmbbl)	90	8	98
Natural gas (bcf)	—	26	26
NGLs (mmbbl)	—	1	1
Total (mmboe)[3]	90	13	103
PV-10 ($million)	$ 1,977	$ 72	$ 2,049

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $82.84 per bbl Brent for oil and NGLs and $2.63 per mmbtu Henry Hub for natural gas at December 31, 2023. The volume-weighted average realized prices over the lives of the properties were $77.30 per bbl of oil and condensate, $26.90 per bbl of NGLs and $3.73 per mcf. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. For more information regarding commodity price risk, please see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**—***Our ability to operate profitably and maintain our business and financial condition are highly dependent on commodity prices, which historically have been very volatile and are driven by numerous factors beyond our control. If oil prices were to significantly decline for a prolonged period of time, our business, financial condition and results of operations may be materially and adversely affected.***"

(2) For proved developed reserves approximately 12% of total and 12% of oil are non-producing.

(3) 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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu, respectively.

PV-10

PV-10 is a non-GAAP financial measure, which is widely used by the industry to understand the present value of oil and gas companies. It 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 does not give effect to derivative transactions or estimated future income taxes. Management believes that PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows at December 31, 2023:

	At December 31, 2023
	(in millions)
California PV-10	$ 1,977
Utah PV-10	72
Total Company PV-10	2,049
Less: Present value of future income taxes discounted at 10%	(366)
Standardized measure of discounted future net cash flows	$ 1,683

Proved Reserves Additions

Our overall proved reserves increased two mmboe, or 2%, before production. The increase was largely due to the Macpherson Acquisition and extensions in our California properties, partially offset by revisions of previous estimates. We replaced 176% of our California production and 19% of our total Company production, with additional proved reserves. The total changes to our proved reserves from December 31, 2022 to December 31, 2023 were as follows:

	California (San Joaquin basin)	Utah (Uinta basin)	Total
		(in mmboe)(1)	
Beginning balance as of December 31, 2022	84	26	110
Extensions and discoveries	5	—	5
Revisions of previous estimates	(1)	(11)	(12)
Purchases of minerals in place	9	—	9
Current year production	(7)	(2)	(9)
Ending balance as of December 31, 2023	90	13	103

(1) 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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu, respectively.

Extensions. During 2023, we added five mmboe of proved reserves from extensions in our California properties, primarily in the Hill Belridge Field, due to an increase in our proved acreage based on drilling activity.

Revisions of previous estimates.

Revisions related to price - Product price changes affect the proved reserves we record. For example, in certain price environments, higher prices can increase the economically recoverable reserves in our operations when the extra margin extends their expected life and renders more projects economic. Conversely, when prices drop, we can experience the opposite effects. In 2023, our total net negative price revision was three mmboe in Utah.

Other revisions - Other revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data. In 2023, we had downward other revisions of one mmboe in California and eight mmboe in Utah. The negative other revisions in California were due to changes to timing of development plans, offset by positive revisions based on sidetracks and workovers that were identified. The negative other revisions in Utah were largely due to the change in timing of development plans.

Purchases of minerals in place. We added nine mmboe of proved reserves in California through the Macpherson Acquisition and a small working interest acquisition in Kern County in December 2023.

Current Year Production - Please refer to "Item 7. **Management's Discussion and Analysis of Financial Condition and Results of Operations—Certain Operating and Financial Information**" for discussion of our current year production.

Proved Undeveloped Reserves Changes

Our California proved undeveloped reserves increased three mmboe in 2023 largely due to extensions, partially offset by revisions. The total changes to our proved undeveloped reserves from December 31, 2022 to December 31, 2023 were as follows:

	California (San Joaquin and Ventura basins)	Utah (Uinta basin)	Total
		(in mmboe)(1)	
Beginning balance as of December 31, 2022	41	7	48
Extensions and discoveries	5	—	5
Revisions of previous estimates	(1)	(5)	(6)
Reclassifications to proved developed	(1)	—	(1)
Ending balance as of December 31, 2023	44	2	46

(1) 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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu, respectively.

Extensions. During 2023, we added five mmboe of proved undeveloped reserves from extensions from unproven locations in Hill Belridge Field, due to an increase in our proved acreage based on prior drilling activity.

Revisions of previous estimates.

Other revisions - In 2023, we had negative other revisions of six mmboe. The PUD negative revisions are due to the changes in the five year development plan, with the majority of revisions in Utah.

Reclassifications to proved developed. In 2023, we shifted a large portion of our development efforts to sidetracks, which have high returns and capital efficiency. Additionally, we transferred approximately one mmboe of proved undeveloped reserves to the proved developed category in 2023, in connection with our development activity in our South Midway-Sunset field, spending approximately $12 million of capital. We expect to have sufficient future capital to develop our proved undeveloped reserves at December 31, 2023 within five years of their original booking date. If prices decrease substantially below current levels for a prolonged period of time, we may be required to reduce expected capital expenditures over the next five years, potentially impacting either the quantity or the development timing of proved undeveloped reserves. Our year-end PUD reserves are determined and classified as such in accordance with SEC guidelines for development within five years. Management has made the necessary commitment and we expect to have sufficient future capital to develop all of our proved undeveloped reserves, though sustained delay in the ability to obtain necessary permits may require us to revise our bookings in the future. For additional details, see "Item 1A. Risk Factors—**Risks Related to Regulatory Matters**—***Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change the requirements governing our operations, including the permitting approval process for oil and gas exploration, extraction, operations and production activities; well stimulation and other enhanced production techniques; and***

fluid injection or disposal activities, any of which could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy and plans."

Reserves Evaluation and Review Process

Independent engineers, DeGolyer and MacNaughton ("D&M"), prepared our reserve estimates reported herein. The process performed by D&M to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data provided by us. When preparing the reserve estimates, D&M did not independently verify the accuracy and completeness of the information and data furnished by us with respect to ownership interests, production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of D&M's work, something came to their attention that brought into question the validity or sufficiency of any such information or data, they would not rely on such information or data until they had satisfactorily resolved their related questions. The estimates of reserves conform to SEC guidelines, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years. Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. Proved reserves estimates are established using standard geological and engineering technologies and computational methods, which are generally accepted by the petroleum industry. The proved reserves additions are primarily prepared by production history or analogy, which use historical production and analogous type curves that are based on decline curve analysis. We further establish reasonable certainty of our proved reserves estimates using geological and geophysical information to establish reservoir continuity between penetrations, downhole completion information, electrical logs, radioactivity logs, core analyses, available seismic data, and historical well cost, operating expense and commodity revenue data.

D&M also prepared estimates with respect to reserves categorization, using the definitions of proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

Our internal control over the preparation of reserves estimates is designed to provide reasonable assurance regarding the reliability of our reserves estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by our Director of Corporate Reserves and Planning, who has a Bachelors of Science in Chemical Engineering from the University of Kentucky and more than 20 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, and presented to our Board of Directors. Within D&M, the technical person primarily responsible for reviewing our reserves estimates is a Licensed Professional Engineer in the State of Texas, has a Master of Science and Doctor of Philosophy degrees in Petroleum Engineering and has more than 10 years of experience in oil and gas reservoir studies and reserves evaluations.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured exactly. For more information, see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**—***Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be different from estimates.***"

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2023, we have approximately 701 gross (696 net) drilling locations attributable to our proved undeveloped reserves. The near-term development plan focuses on sidetracks and drilling in CEQA covered areas in California and on new well drilling in Utah. The decrease in proven drilling locations was based on the changes in our five year development plan. We use production data and experience gains from our development programs to identify and prioritize development of this proven drilling inventory. These drilling locations are included in our inventory only after they have been evaluated technically and are deemed to have a high likelihood of being drilled within a five-year time frame. As a result of technical evaluation of geologic and engineering data, it can be estimated with reasonable certainty that reserves from these locations are commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations. Management has made the necessary commitment and we expect to have sufficient future capital to develop all of our proved undeveloped reserves, though sustained delay in the ability to obtain necessary permits may require us to revise our bookings in the future. For more information, see "Regulatory Matters—California Permitting Considerations."

Unproven Drilling Locations

We have also identified a multi-year inventory of 8,515 gross (8,509 net) unproven drilling locations as of December 31, 2023. Our unproven drilling locations are specifically identified on a field-by-field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These drilling locations primarily include (i) infill drilling locations, (ii) additional locations due to field extensions or (iii) thermal recovery project expansions, some of which are currently in the pilot phase across our properties, but have yet to be determined to be proven locations. We believe the assumptions and data used to estimate these drilling locations are consistent with established industry practices based on the type of recovery process we are using. Please see "Regulation of Health, Safety and Environmental Matters" for additional discussion of the laws and regulations that impact our ability to drill and develop our assets, including regulatory approval and permitting requirements.

We plan to analyze our acreage for exploration drilling opportunities at appropriate levels. We expect to use internally generated information and proprietary models consisting of data from analog plays, 3-D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons.

Well Spacing Determination

Our well spacing determinations in the above categories of identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery process employed (i.e., primary, waterflood and thermal recovery). Spacing intervals can vary between various reservoirs and recovery techniques. Our development spacing can be less than one acre for a thermal steamflood development in California.

Drilling Schedule

Our identified drilling locations have been scheduled as part of our current multi-year drilling schedule or are expected to be scheduled in the future. However, we may not drill our identified sites at the times scheduled or at all. We view the risk profile for our prospective drilling locations and any exploration drilling locations we may identify in the future as being higher than for our other proved drilling locations.

Our ability to drill and develop our identified drilling locations profitably or at all depends on a number of variables, many of which are outside of our control, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and permits, available transportation capacity and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. For a discussion of the risks associated with our drilling program, see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**—***We may not drill our identified sites at the times we scheduled or at all.***" See additional discussion of the regulatory environment below in "Regulatory Matters—*California Permitting Considerations.*"

The table below sets forth our proved undeveloped drilling locations and unproven drilling locations as of December 31, 2023:

	PUD Drilling Locations (Gross)	Unproven Drilling Locations (Gross)	Total Drilling Locations (Gross)
	Oil, Natural Gas Wells and Injection Wells	Oil, Natural Gas and Injection Wells	Oil, Natural Gas and Injection Wells
California	668	7,159	7,827
Utah	33	1,356	1,389
Total Identified Drilling Locations	701	8,515	9,216

The following tables sets forth information regarding production volumes for fields with equal to or greater than 15% of our total proved reserves for each of the periods indicated:

	Year Ended December 31,		
	2023	2022	2021
SJV Midway Sunset			
Total production[(1)]:			
Oil (mbbls)	5,369	5,630	5,666
Natural gas (bcf)	—	—	—
NGLs (mbbls)	—	—	—
Total (mboe)[(2)]	5,369	5,630	5,666

	Year Ended December 31,		
	2023	2022	2021
SJV Belridge Hill			
Total production[(1)]:			
Oil (mbbls)	1,459	1,551	1,505
Natural gas (bcf)	—	—	—
NGLs (mbbls)	—	—	—
Total (mboe)[(2)]	1,459	1,551	1,505

	Year Ended December 31,		
	2023	2022	2021
Uinta			
Total production[(1)]:			
Oil (mbbls)	*	1,010	*
Natural gas (bcf)	*	3,502	*
NGLs (mbbls)	*	144	*
Total (mboe)[(2)]		1,737	

* Represented less than 15% of our total proved reserves for the periods indicated.

(1) Production represents volumes sold during the period.

(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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu, respectively.

Productive Wells

As of December 31, 2023, we had a total of 3,981 gross (3,811 net) productive wells (including 584 gross and 566 net steamflood and waterflood injection wells), approximately 100% of which were oil wells. Our average working interests in our productive wells is approximately 96%. All of our Uinta basin oil wells produce associated gas and NGLs. We were participating in 14 steamflood projects and three waterflood projects located in the San Joaquin basin, and two waterflood projects located in the Uinta basin as of the end of 2023.

The following table sets forth our productive oil and natural gas wells (both producing and capable of producing) as of December 31, 2023:

	California (San Joaquin basin)	Utah (Uinta basin)	Total
Oil			
Gross[(1)]	2,731	1,250	3,981
Net[(2)]	2,606	1,205	3,811
Gas[(3)]			
Gross[(1)]	—	—	—
Net[(2)]	—	—	—

(1) The total number of wells in which interests are owned. Includes a total of 584 steamflood and waterflood injection wells with 572 in California and 12 in Utah.

(2) The sum of fractional interests.

(3) In Utah, we have associated gas in a portion of our oil wells, which are reported as oil wells.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2023:

	California (San Joaquin basin)	Utah (Uinta)	Total
Developed[(1)]			
Gross[(2)]	11,876	47,107	58,983
Net[(3)]	11,426	45,332	56,758
Undeveloped[(4)]			
Gross[(2)]	13,001	62,903	75,904
Net[(3)]	8,470	54,017	62,487

(1) Acres spaced or assigned to productive wells.

(2) Total acres in which we hold an interest.

(3) Sum of fractional interests owned based on working interests or interests under arrangements similar to production sharing contracts.

(4) Acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the acreage contains proved reserves.

Participation in Wells Being Drilled

As of December 31, 2023, we were not participating in any uncompleted wells.

Drilling Activity

The following table shows the net development wells we drilled during the periods indicated, which include delineation and temperature observation wells per our development plan. We did not drill any exploratory wells during the periods presented. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value.

In connection with the closing of the Macpherson Acquisition in September 2023, we reallocated a significant portion of the 2023 capital expenditures budget to fund a portion of the purchase price. The capital budget was adjusted to reflect the reduced need for drilling activities on the legacy Berry assets in 2023 due to the addition of producing assets, allowing Berry to meet production targets while reducing drilling, workover and other activities on the legacy Berry assets in California and Utah.

	California (San Joaquin and Ventura basins[3])	Utah (Uinta basin)	Total
2023			
Oil[1][2]	33	—	33
Natural Gas	—	—	—
Dry	—	—	—
2022			
Oil[1][2]	72	13	85
Natural Gas	—	—	—
Dry	—	—	—
2021			
Oil[1]	181	10	191
Natural Gas	—	—	—
Dry	—	—	—

(1) Includes injector wells.

(2) Includes two and 12 wells that had not yet been connected to gathering systems in California in 2023 and 2022, respectively.

(3) Effective October 2021, we completed the sale of our Placerita Field property in the Ventura Basin in Los Angeles County, California, which did not include any wells in 2021.

Methods of Recovery and Marketing Arrangements

We seek to be the operator of our properties so that we can develop and implement drilling programs and optimization projects that not only replace production but add value through reserve and production growth and future operational synergies. We have an average of 96% working interest for operated wells and 98% operating control in our properties.

Our California operations are primarily focused on the Sandstones (thermal and waterflood), thermal Diatomite and Hill Diatomite development areas. We also have operations in the Uinta basin in Utah, as noted in the following table.

State	Project Type	Well Type	Completion Type	Recovery Mechanism
California	Thermal Sandstones	Vertical / Horizontal	Perforation/Slotted liner/ gravel pack	Continuous and cyclic steam injection
California	Sandstones (non-thermal)	Vertical/ Horizontal	Perforation, Slotted liner	Waterflood, Primary
California	Thermal Diatomite	Vertical	Short interval perforations	High-pressure cyclic steam injection
California	Hill Diatomite (non-thermal)	Vertical	Hydraulic stimulation, low intensity pin point	Pressure depletion augmented with water injection
Utah	Uinta	Vertical / Horizontal	Low intensity hydraulic stimulation	Pressure depletion

Enhanced Oil Recovery

Most of our assets in California consist of heavy crude oil, which requires a reduction in viscosity, typically driven by heat supplied in the form of steam injected into the oil producing formation, thereby allowing oil to flow to the wellbore for production. We have both cyclic and continuous steam injection projects in the San Joaquin basin, all in Kern County and in fields such as Midway-Sunset, South Belridge, McKittrick and Poso Creek. This technique has many years of demonstrated success in thousands of wells drilled by us and others. We intend to continue employing both recovery techniques as long as a favorable oil to gas price spread exists. Full development of these projects typically takes multiple years and involves upfront infrastructure construction for steam and water processing facilities and follow on development drilling. These thermal recovery projects are generally shallow in depth (600 to 2,500 ft) and the wells are relatively inexpensive to drill and complete at approximately $600,000 per well. Therefore, we can normally implement a drilling program quickly with attractive rates of return. Production in the basin, where supported by lower oil viscosities, is also available through primary production and waterflood injection in fields such as Midway-Sunset, South Belridge and Round Mountain.

Cogeneration Steam Supply and Conventional Steam Generation

We produce oil from heavy crude reservoirs using steam to heat the oil so that it will flow to the wellbore for production. To assist in this operation, we own and operate four natural gas burning cogeneration plants that produce electricity and steam: (i) a 38 MW facility ("Cogen 38"), an 18 MW facility ("Cogen 18") and a 5 MW facility ("Pan Fee Cogen"), each located in the Midway-Sunset Field and (ii) another 5MW facility ("21Z Cogen") located in the McKittrick Field. Cogeneration plants, also referred to as combined heat and power plants, use hot turbine exhaust to produce steam while generating electrical power. This combined process is more efficient than producing power or steam separately. For more information, see "—Marketing Arrangements" and "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**—***We are dependent on our cogeneration facilities to produce steam for our operations. Contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations.***"

We own 59 fully permitted conventional steam generators. The number of generators operated at any point in time is dependent on (i) the steam volume required to achieve our targeted injection rate and (ii) the price of natural gas compared to our oil production rate and the realized price of oil sold. Ownership of these varied steam generation facilities allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. 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.

Marketing Arrangements

We market crude oil, natural gas, NGLs, gas purchasing and electricity.

Crude Oil. Approximately 92% of our California crude oil production is connected to California markets via crude oil pipelines. We generally do not transport, refine or process the crude oil we produce and do not have any long-term crude oil transportation arrangements in place. California oil prices are Brent-influenced as California refiners import approximately 75% of the state's demand from OPEC+ countries and other waterborne sources. This dynamic has led to periods, including recent years, where the price for the primary benchmark, Midway-Sunset, a 13° API heavy crude, has been equal to or exceeded the price for WTI, a light 40° API crude. We believe that receiving Brent-influenced pricing contributes to our ability to continue realizing strong cash margins in California. Our oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to purchaser-posted prices for the producing area. We sell all of our oil production under short-term contracts. The waxy quality of oil in Utah has historically limited sales primarily to the Salt Lake City market, which is largely dependent on the supply and demand of oil in the area. The recent success of a tight oil play in the basin has increased supply and put downward pressure on physical oil prices. Due to these circumstances, we are endeavoring to sell our crude to markets outside the basin. Export options to other markets via rail are available and have been used in the past, but are comparatively expensive. We also entered into oil hedges to protect our operating expenses and other costs from price fluctuations.

Natural Gas. Our natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area. Our natural gas production is sold to purchasers under seasonal spot price or index contracts. We sell all of our natural gas and NGL production under short-term contracts at market-sensitive or spot prices. In certain circumstances, we have entered into natural gas processing contracts whereby the residual natural gas is sold under short-term contracts but the related NGLs are sold under long-term contracts. In all such cases, the residual natural gas and NGLs are sold at market-sensitive index prices.

NGLs. We do not have long-term or long-haul interstate NGL transportation agreements. We sell substantially all of our NGLs to third parties using market-based pricing. Our NGL sales are generally pursuant to processing contracts or short-term sales contracts.

Gas Purchasing. We purchase natural gas under short-term market-based contracts. We have long-term pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that help reduce our exposure to fuel gas purchase price fluctuations. We also enter into hedges for gas purchases to protect our operating expenses from price fluctuations.

Electricity Generation. Our cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. The total nameplate electrical generation capacity of our four cogeneration facilities, which are centrally located on certain of our oil producing properties, is approximately 66 MW. The steam generated by each facility is capable of being delivered to numerous wells that require steam for our thermal recovery processes. The main purpose of the cogeneration facilities is to reduce the steam and electricity costs in our heavy oil operations.

Electricity and steam produced from our Pan Fee Cogen and 21Z Cogen facilities are used solely for field operations.

For the year ended December 31, 2023, we sold approximately 326 megawatt-hours (“MWhs”) per day of cogeneration power into the grid and on average consumed approximately 297 MWhs per day of cogeneration power for lease operations. The four cogeneration facilities produced an average of approximately 14,000 barrels of steam per day. At various times during 2023, we made the economic decision to reduce our gas consumption in California by temporarily reducing the generation of electricity and steam from our cogeneration facilities. Contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations.

Electricity Sales Contracts. We sell electricity produced by one of our cogeneration facilities under a long-term PPA approved by the California Public Utilities Commission (the “CPUC”) to a California investor-owned utility, Pacific Gas and Electric (“PG&E”). The PPA expires in November 2026.

Principal Customers

For the year ended December 31, 2023, sales to PBF Holding, Chevron and Phillips 66, accounted for approximately 41%, 20%, and 10%, respectively, of our sales. At December 31, 2023, trade accounts receivable from two customers represented approximately 31% and 25% of our receivables.

If we were to lose any one of our major oil and natural gas purchasers, the loss could cease or delay production and sale of our oil and natural gas in that particular purchaser’s service area and could have a detrimental effect on the prices and volumes of oil, natural gas and NGLs that we are able to sell. For more information related to marketing risks, see “Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**.”

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a preliminary review of the title to our properties at the time of acquisition. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. We do not commence drilling operations on a property until we have cured known title defects on such property that are material to the project. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, overriding royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations, or net profits interests.

Competition

The oil and natural gas industry is highly competitive. In our upstream E&P business, we historically encounter strong competition from other companies, including independent operators in acquiring properties, contracting for drilling and other related services, and securing trained personnel. We also are affected by competition for drilling rigs and related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. The lower-cost, commoditized nature of our equipment and service providers partially insulates us from the cost inflation pressures experienced by producers in unconventional plays. We are unable to predict when, or if, such shortages may occur or how they would affect our drilling program.

Through CJWS we provide services in the California market where our competitors are comprised of both small regional contractors as well as larger companies with international operations. CJWS’s revenues and earnings can be affected by several factors, including changes in competition, fluctuations in drilling and completion activity by its customers, perceptions of future prices of oil and gas, government regulation, disruptions caused by weather, pandemics and general economic conditions. We believe that the principal competitive factors are price, performance, service quality, safety, and response time. For more information regarding competition and the related risks in the oil and natural gas industry, please see “Item 1A. Risk Factors—**Risks Related to Our Operations and**

Industry—***Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.*** ”

We also face indirect competition from alternative energy sources, such as wind or solar power, and these alternative energy sources could become even more competitive as California and the federal government develop renewable energy and climate-related policies.

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. For example, during the first quarter of 2023, we experienced an increase in costs, production downtime and transportation delays due to the unprecedented snowy and rainy weather in Utah and California. Unusually heavy rains caused flooding and power outages which adversely impacted our ability to operate in California, while Utah was impacted by historic snowfall. Beginning April 2023, the weather improved and our production returned to normal levels for the remainder of 2023.

Cold weather conditions drove high natural gas prices in 2023. In California, we experienced a significant increase in the first quarter of 2023, with gas prices briefly as high as $54.31 per mmbtu (SoCal Gas city-gate). We pivoted and reduced our gas consumption in California by temporarily shutting down one of our cogeneration facilities and reducing steam generation in other parts of our operation, which negatively impacted production. 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. Natural gas prices in the western US relative to Henry Hub experienced a decline in 2023 compared to 2022. Late in the fourth quarter of 2023, prices experienced further decline compared to the beginning of the quarter. This trend has continued into early 2024. Our current expectations are that the natural gas prices will continue to decrease in early 2024 due to an increase in natural gas production and increased natural gas storage inventory levels. 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.

Regulatory Matters

Regulation of the Oil and Gas Industry

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. A combination of federal, state and local laws and regulations govern most aspects of our activities, and federal, state and local agencies may assert overlapping authority to regulate in these areas, including:

- oil and natural gas production, including siting and spacing of wells and facilities on federal, state and private lands with associated conditions or mitigation measures;
- methods of constructing, drilling, completing, stimulating, operating, inspecting, maintaining and abandoning wells;
- the design, construction, operation, inspection, maintenance and decommissioning of facilities, such as natural gas processing plants, power plants, compressors and liquid and natural gas pipelines or gathering lines;

- techniques for improved or enhanced recovery, such as steam or fluid injection for pressure management;
- the sourcing and disposal of water used in the drilling, completion, stimulation, maintenance and improved or enhanced recovery processes;
- the posting of bonds or other financial assurance to drill, operate and abandon or decommission wells and facilities; and
- the transportation, marketing and sale of our products.

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 on the industry 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 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.

CalGEM is California's primary regulator of the oil and natural gas drilling and production activities on private and state lands, with additional oversight from the California State Lands Commission's administration of state surface and mineral interests, as well as other state and local agencies. The BLM exercises similar jurisdiction on federal lands in California, on which CalGEM also asserts jurisdiction over certain activities. The California Legislature has significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the California State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years, and CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements. In addition, from time to time legislation has been introduced in the California State Legislature seeking to further restrict or prohibit certain oil and gas operations, and the U.S. Congress and federal agencies also regularly seek to revise environmental laws and regulations.

A discussion of the potential impact that government regulations, including those regarding environmental matters, may have upon our business, operations, capital expenditures, earnings and competitive position follows. For more information related to the regulatory risks that could potentially have a material effect on the Company, see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**."

California Permitting Considerations

The issuance of permits and other approvals for drilling and production activities by state and local agencies or by federal agencies may be subject to environmental reviews under the California Environmental Quality Act ("CEQA") or the National Environmental Policy Act ("NEPA"), respectively, which in the past has resulted, and in the future may result, in delays in the issuance of necessary permits and approvals and the imposition of onerous mitigation measures or restrictions, among other things. For example, before an operator can pursue drilling operations in California, they must first obtain local government permission to engage in an oil and gas production land use, which requires the local government to conduct a CEQA-compliant review to evaluate the environmental impact that the proposed land use may cause, including on habitats, neighboring communities, air quality, water quality and other environmental considerations. CEQA imposes similar obligations on permitting decisions by state and local agencies. Prior to issuing the permits necessary for the conduct of certain operations (for example, to drill a new well), CalGEM requires an operator to identify the manner in which CEQA has been satisfied, which is typically through either an environmental impact review or an exemption by a state or local agency.

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 CEQA and/or 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 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 (the "Kern County EIR"). However, the Kern County EIR was legally challenged in 2020, with a recent decision handed down on March 7, 2024, directing Kern County to prepare a revised EIR that corrects certain CEQA violations, circulate the revised EIR for public review and comment, and prepare and publish responses to any comments received before certifying the revised EIR. The suspension of the Kern County EIR, and the reviewing and approving of permits pursuant to the Kern County zoning ordinance, remains in effect. Accordingly, our ability to rely on the Kern County 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, throughout 2023 and year to date in 2024, neither we nor any other operator received permits to drill new wells using the Kern County EIR to demonstrate CEQA compliance. In fact, since January 2023, relatively few permits to drill new wells in California have been issued to any oil producer.

Currently, as a result of the Kern County EIR legal challenges, in order to obtain permits for drilling new wells in Kern County, we must demonstrate compliance with CEQA to CalGEM through means other than the Kern County EIR. Berry has a separate environmental impact analysis covering certain assets, and in the past we have have been successful in obtaining permits to drill new wells in the covered areas. However, we began to experience delays in the issuance of drill permits in those areas during the third quarter of 2023, which we believe is due to changes in CalGEM's CEQA review process. Additionally, in the third quarter of 2023, we started to experience delays in the approval process for workover and sidetrack permits as well, which we believe is also due to changes in CalGEM's review process. While the timing of receiving these permits has recently been inconsistent, we have continued to receive permits.

Approximately 95% of our production in 2023 came from our base production, with the remainder from 33 wells drilled in California during the year (five new wells and 28 sidetracks), workovers and other activities related to existing wellbores, and production acquired from the Macpherson Acquisition. Similar to 2023, our 2024 plans assume that we will not receive permits to drill new wells and instead focus on drilling sidetracks and working over existing wells. We also expect to benefit from a full year of production from the assets acquired in the Macpherson Acquisition and other bolt-on acquisitions at the end of 2023, which should help keep our production essentially flat in 2024. We currently have sufficient permits in hand that should allow us to maintain sidetrack activity through around July 2024 and a continuous workover campaign for approximately the first half of the year. We are in the process of obtaining the remaining permits needed to support our 2024 plans, while also working to obtain additional permits to support future plans. The permitting applications necessary to hold production flat for the full year 2024, none of which are dependent on the Kern County EIR, have been submitted to CalGEM and are pending approval.

With respect to potential future plans, we have submitted new drill permits that are pending CalGEM review; 14 are for wells in areas for which we have a separate environmental impact analysis and 75 are in areas where the Kern County EIR is needed to demonstrate CEQA compliance. With respect to the latter, those 75 permit applications have already received local approval via the issuance of a Kern County permit, and to help ensure efficient processing and final approval of those permits by CalGEM if and when the Kern County EIR is reinstated, we are seeking conditional approval of those permits from CalGEM, subject to reinstatement of the Kern County EIR to confirm CEQA compliance. See Part I, Item 1A. “Risk Factors” in this Annual Report for more information regarding the Kern County EIR and other permitting considerations.

Separately, in February 2021, the Center for Biological Diversity filed suit against CalGEM alleging that its reliance on the Kern County EIR for oil and gas decisions violates CEQA, and that an independent environmental impact review in compliance with CEQA is required by CalGEM before the agency can issue oil and gas permits and approvals. Most recently, the Alameda County Superior Court denied CalGEM’s motion for judgment on the pleadings and the lawsuit remains ongoing. We cannot predict its ultimate outcome or whether it could result in changes to the requirements for demonstrating compliance with CEQA and the permitting process, even if the Kern County EIR is ultimately deemed sufficient and reinstated.

Among other things, if we are unable to obtain new well drill permits through 2024, it could result in the loss of some amount of the proved undeveloped reserves that expire by December 31, 2025 identified in our December 31, 2023 reserve report.

Setbacks

Separately, on September 16, 2022, the Governor of California signed into law Senate Bill No. 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 effective January 1, 2023. On January 6, 2023, CalGEM’s emergency regulations to support implementation of Senate Bill No. 1137 were approved by the Office of Administrative Law and final regulations were published. The regulations include applicable requirements of notice to property owners and tenants regarding the work performed and offering the sampling of test water wells or surface water before and after drilling; the contents of required notices for new production facilities; the annual submission of a sensitive receptor inventory and sensitive receptor map and the contents and format of the same; and the requirements of statements where operators have determined a location not to be within a health protection zone. Additional provisions of Senate Bill No. 1137, include, among others, the imposition of HSE controls applicable to wells located within this distance of sensitive receptors related to noise, light, and dust pollution controls and air emission monitoring, and the immediate suspension of operations at production facilities determined not to be in compliance with certain air emission requirements. The latter provisions would be effective January 1, 2025, if Senate Bill No. 1137 is ratified in the November 2024 election.

In December 2022, proponents of a voter referendum (the “Referendum”) collected more than the requisite number of signatures required to put Senate Bill No. 1137 on the November 2024 ballot for ratification by voters. 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, although any stay could be delayed if there are legal challenges to the Secretary of State’s certification.

The majority of our production is in rural areas in the San Joaquin basin and is unlikely to be affected by Senate Bill No. 1137 should it be ratified in the November 2024 election. We are actively pursuing mitigation efforts with respect to the potential impacts on current and planned wells, but it is possible that we are unable to ultimately develop those properties. We continue to assess the impacts of this rule, but we currently estimate that approximately 10% of our overall proved reserves 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.

The potential exists for additional legislation in the future that could adversely impact our operations. For example, in 2023, a legislator introduced Senate Bill No. 556 (“SB 556”) which provides for joint and several liability of operators and owners of an entity that owns an oil and gas production facility for certain adverse health conditions such as respiratory ailments, cancer diagnoses and certain pregnancy complications, experienced by individuals living within 3,200 feet of such facility, subject to limited defenses. Senate Bill No. 556 also provided for civil penalties to be assessed against potentially responsible parties. Although SB 556 failed passage, Assembly

Bill No. 3155 (“AB 3155”) was introduced on February 16, 2024 and contains substantially the same provisions as SB 556.

We continue to assess the impacts of Senate Bill No. 1137 and the potential impacts of AB 3155 to our ability to operate and any increased exposure to liability.

California Disclosure Laws for Climate-Related Risks

In October 2023, the Governor of California 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 laws have been challenged in federal court. Enhanced climate-related disclosures pursuant to the requirements of SB 253 and SB 261 could also lead to reputational or other harm with various stakeholders or adversely impact our access to capital to the extent our disclosures may not align with stakeholder expectations and may increase our litigation risks.

California Underground Injection Control Regulations

The federal Safe Drinking Water Act (“SDWA”) and the California Underground Injection Control (“UIC”) program promulgated under the SDWA and relevant state laws regulate the drilling and operation of injection and disposal wells that manage produced water (brine wastewater containing salt and other constituents produced by oil and natural gas wells). Permits must be obtained before developing and using deep injection wells for the disposal of produced water or for enhanced oil recovery, and well casing integrity monitoring must be conducted periodically to ensure the well casing is not leaking produced water to groundwater. The U.S. Environmental Protection Agency (“EPA”) directly administers groundwater protection programs in some states, and in others, such as California, administration is delegated to the state.

Effective April 2019, CalGEM finalized new UIC regulations, which affects specific types of wells: (i) those that inject water or steam for enhanced oil recovery and (ii) those that return the briny groundwater that comes up from oil formations during production. The key regulations include stronger testing requirements designed to identify potential leaks, increased data requirements to ensure proposed projects are fully evaluated, continuous well pressure monitoring, requirements to automatically cease injection when there is a risk to safety or the environment, and requirements to disclose chemical additives for injection wells close to water supply wells. Notwithstanding these changes, separately, in September 2021 the EPA issued a letter to the California Natural Resources Agency and the State Water Resources Control Board regarding California’s compliance with a 2015 compliance plan relating to California’s process for approving aquifer exemptions under the UIC regulations and submitting those approvals to EPA for review. The letter requested that California take appropriate action by September 2022, or the EPA would consider taking additional action to impose limits on California’s administration of the UIC program, withhold federal funds for the administration of the UIC program, and direct orders to oil and gas operators injecting into formations not authorized by the EPA, amongst other measures. The State responded in October 2021 with a proposed compliance plan and a follow-up letter in August 2022 providing a mid-year update, but, to date, the EPA has not yet responded. Additional limitations on injection well operations, increased federal oversight of the UIC permitting process, and a lack of funds for California to administer permits under the UIC program all have the potential to adversely affect our operations and result in increased operational and compliance costs.

Uncertainty surrounding compliance with UIC regulations has from time to time resulted in delays in obtaining UIC permits for enhanced oil recovery, disposal of oilfield wastes and injection wells, which in turn can delay our ability to obtain other permits needed to conduct our planned operations. Moreover, concerns related to potential groundwater contamination issues have resulted in increased scrutiny with respect to UIC permitting and other oil and gas activities in California. It is possible that more stringent regulations or restrictions on our ability to obtain UIC permits for enhanced oil recovery and disposal of oilfield wastes could be imposed upon our operations in the future. Additionally, CalGEM has indicated that is coordinating with the California State Water Resources Control Board to propose rules regarding enhanced reviews for injection well permitting decisions. Any such changes could adversely impact our operations. For example, while "infill drilling" has been considered exempt from certain CalGEM permitting requirements in the past, such as the need to obtain a new project approval letter ("PAL"), CalGEM appears to be limiting the instance where it considers proposed drilling as "infill" of areas already given over to oilfield uses and impacts. An infill well occurs when an operator seeks to change the location of an active injection well or add a new injection well not previously identified in the project application. In March 2022, CalGEM issued a Notice to Operators informing operators of new checklist documentation used in connection with the approval of injection wells, which includes adding non-expansion infill wells. Changes in the process for approving infill wells has the potential to delay permitting injection and other activities, and could result in increased compliance costs on our operations. Our future plans beyond 2024 may be impacted by an inability to timely obtain certain permits needed to carry out our drilling and development plans due to a delay in obtaining the requisite UIC permits. In the past, we have been able to modify our drilling and development plans and obtain the permits necessary to support ongoing operations despite these permitting uncertainties, but there is no guarantee that we can continue to successfully manage these issues in the future.

California Requirements for Plugging and Abandonment of Oil and Gas Facilities

In California, an idle well is one that has not been used for two years or more and has not yet been permanently sealed pursuant to CalGEM regulations. An idle well that has no identifiable, responsible operator and as a result becomes a burden of the State is referred to as an orphan well. In April 2019, CalGEM issued updated idle well regulations, including a comprehensive well testing regime to demonstrate the mechanical integrity of idle wells, a compliance schedule for testing or plugging and abandoning idle wells, the collection of data necessary to prioritize testing and/or plugging idle wells, an engineering analysis for each well idled 15 years or longer, and requirements for active observation wells. Additionally, operators are required to either submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or pay additional annual fees and perform additional testing to retain greater flexibility to return long-term idle wells to service in the future. Also, in 2019, the Governor of California signed Assembly Bill 1057, legislation requiring CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap. This legislation also expanded CalGEM's duties, effective January 1, 2020, to include public health and safety and reducing or mitigating greenhouse gas ("GHG") emissions while meeting the state's energy needs.

To date, we have fulfilled the conditions of our idle well management plans and we are on track to do so again in 2024. In 2023, we spent approximately $18 million on our plugging and abandonment activities. In 2024, we currently estimate spending will be approximately $21 million to $24 million for such activities in order to meet our annual plugging and abandonment obligations.

In the fourth quarter of 2021, we acquired CJWS as a new business line to provide standard well services to the industry in California, including plugging and abandoning idle wells across California for ourselves and other operators, as well as the State of California. We believe that CJWS is well positioned to capture both state and federal funds to help remediate idle wells; as of December 31, 2023, California has approximately 34,000 idle wells, of which approximately 5,300 are believed to be deserted or orphaned wells according to CalGEM.

Separate from the requirements for plugging of idled wells, the Governor of California also signed Assembly Bill 1167 ('AB 1167') into law in October 2023, which 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 being acquired. 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 Governor of California called for further legislative changes to the new requirements for the acquired assets to mitigate the potential risk of an increase in the number of orphaned wells becoming state liabilities following the implementation of the law; however, to date, no bills have yet been introduced to address the Governor of California's request. To the extent the law is implemented as written, we could face increased bonding or other financial-assurance related costs in connection with new acquisitions, or may find it infeasible to pursue certain acquisitions because of such costs.

Additional Actions Impacting Oil and Gas Activities in California

In recent years the Governor of California and California Legislature have taken a series of actions that seek to reduce both the supply of and demand for fossil fuels in the state. For example, in September 2022, the Governor of California signed Senate Bill No. 1279 into law, which codifies an executive order previously issued by the Governor's Office requiring the state to achieve carbon neutrality by 2045. In addition, the Governor of California previously issued an executive order that established several goals and directed several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of emissions-producing vehicles; developing strategies for the closure and repurposing of oil and gas facilities in California; and calling on the California State Legislature to enact new laws prohibiting hydraulic fracturing in the state by 2024. In February 2024, CalGEM issued a proposed regulation to formally end hydraulic fracturing in the state, introducing a complete restriction on approval of permit applications to conduct well stimulation treatments. We currently do not perform any hydraulic fracturing in California and our near term plans do not include the development of assets requiring hydraulic fracturing.

Separately, in October 2020, the Governor of California issued an executive order that established a state goal to conserve at least 30% of California's land and coastal waters by 2030 and directed state agencies to implement other measures to mitigate climate change and strengthen biodiversity. At this time, we cannot predict the potential future actions that may result from this order or how such may potentially impact our operations.

Additionally, President Biden signed the Inflation Reduction Act ("IRA") into law on August 16, 2022 which, among other things, imposes a fee on the emissions of methane from certain sources in the oil and natural gas sector and provides significant incentives for renewable energy and low or zero carbon products. Beginning in 2024, the IRA's methane emissions charge imposes a fee on excess methane emissions from certain oil and gas facilities, starting at $900 per metric ton of leaked methane in 2024 and rising to $1,200 in 2025, and $1,500 in 2026 and thereafter. Relatedly, on January 12, 2024, the EPA released a proposed rule implementing the requirements of the IRA methane emissions fee; namely, to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from facilities reporting more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases per year pursuant to the petroleum and natural gas system source category requirements of the agency's Greenhouse Gas Reporting Rule. The imposition of this fee and other provisions of the IRA could increase our operating costs which could adversely affect our business and results of operations.

Restrictions on Oil and Gas Developments on Federal Lands

As of December 31, 2023, approximately 16% and 26% of our net acreage in California and Utah, respectively, is on federal land, which comprises approximately 11% and 16% of our total proved reserves in California and Utah, respectively, and approximately 10% and 12% of our PUD locations in California and Utah, respectively. Additional federal restrictions on oil and gas activities on federal lands may be imposed in the future. For example, on January 27, 2021, President Biden issued an executive order that suspends the issuance of new leases for oil and gas development on federal lands to the extent permitted by law and calls for a review of existing leasing and permitting practices for such activities on federal lands (the order clarifies that it does not restrict such operations on tribal lands including tribal lands that the federal government merely holds in trust). Although the order does not apply to existing operations under valid leases, we cannot guarantee that further action will not be taken to curtail oil and gas development on federal land. The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021 and a permanent injunction in August 2022, effectively halting implementation of the leasing suspension with respect to leases canceled or postponed prior to March 24, 2021. Separately, the Department of the Interior ("DOI") released its report on federal gas leasing and permitting practices in November 2021, referencing a number of recommendations and an overarching intent to modernize the federal oil and gas leasing program, including prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. The IRA responded to one of the report's recommendations and increased onshore royalty rates to 16⅔%. And, in July 2023, the Department of Interior released a proposed rule revising various fiscal terms—bonding requirements, royalty rates and minimum bids—of the onshore federal oil and gas lease program, integrating recommendations from the November 2021 report. While it is not possible at this time to predict the ultimate impact of the proposed rule or these actions, such restrictions on federal oil and gas activities could result in increased costs and adversely impact our operations.

With respect to major federal actions pursuant to NEPA, recent modifications may also impose further restrictions on oil and gas activities on federal lands. In October 2021, the Biden Administration announced three significant changes to a 2020 rule finalized under the Trump Administration. These changes included authorizing agencies to consider the direct, indirect and cumulative effects of major federal actions including upstream and downstream GHG emissions impacts of fossil fuel projects, allowing agencies to determine the purpose and need of a project (thereby allowing consideration of less-harmful alternatives), and affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council on Environmental Quality ("CEQ") regulations, so as to meet the agencies' and public's needs. To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes, a move considered as "Phase I" of the Biden Administration's two-phased approach to modifying NEPA. In July 2023, "Phase 2" of this process, the CEQ released a proposed rule revising the implementing regulations of the procedural provisions of NEPA and implementing amendments to NEPA included in the Fiscal Responsibility Act. The final rule is expected in the second quarter of 2024.

Operations on Tribal Lands

As of December 31, 2023, approximately 67% of our net acreage in Utah is on tribal lands, which comprises approximately 78% of our total proved reserves in Utah, and approximately 76% of our PUD locations in Utah; none of our California assets or operations are located on tribal lands. In addition to potential regulation by federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations promulgated by the Indian tribe with jurisdiction over such lands applies to lessees, operators and other parties on such lands, tribal or allotted. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment and contractor preferences and numerous other matters. Further, lessees and operators on tribal lands may be subject to the jurisdiction of tribal courts, unless there is a specific waiver of sovereign immunity by the relevant tribe allowing resolution of disputes between the tribe and those lessees or operators to occur in federal or state court. These laws, regulations and other issues present unique risks that may impose additional requirements on our operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of our oil and natural gas leases, which in turn may materially and adversely affect our operations on tribal lands.

Restrictions on High-Pressure Cyclic Steam and Well Stimulation Treatments

Our California operations are primarily focused on the thermal Sandstones, thermal Diatomite and Hill Diatomite development areas, of which only our undeveloped thermal Diatomite assets require new high-pressure cyclic steam wells and Belridge Hill Diatomite potentially require well stimulation treatments ("WST") (also known as hydraulic stimulation, hydraulic fracturing or fracking). We have limited our plan in 2024 and we do not have any near term plans that would require WST in our Belridge Hill Diatomite assets. We do rely on other methods to simulate production, including the use of cyclic and continuous steam injection, which is heavily regulated. Any restrictions on the use of those means of simulating production may adversely impact our operations, including causing operational delays, increased costs, and reduced production. However, our ability to conduct such activities has not been prohibited or otherwise restricted by the moratorium on permitting for new high–pressure cyclic steam wells and WST.

As referenced above, in November 2019, the State Department of Conservation issued a press release announcing four actions by CalGEM: (1) a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators; (2) a review and update of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the California State Legislature in 2019 (discussed above); (3) a performance audit of CalGEM's permitting processes for issuing WST permits and PALs for underground injection activities by the State Department of Finance; and (4) an independent review of the technical content of pending WST and PAL applications by Lawrence Livermore National Laboratory. In September 2020, the Governor of California issued an executive order which, among other actions, required CalGEM to complete its public health and safety review and propose additional regulations and noted the Governor of California's intent to seek legislation to end the issuance of new hydraulic fracturing permits by 2024. In February, 2024, CalGEM issued a proposed regulation to formally end hydraulic fracturing in California; the executive order and proposal are further discussed above under "—Additional Actions Impacting Oil and Gas Activities in California." In January 2020, CalGEM issued a formal notice to operators, including us, that they had issued restrictions imposing the previously announced moratorium to prohibit new underground oil-extraction wells from using high-pressure cyclic steaming process. In February of 2022, CalGEM issued letters to operators who had conducted high pressure cyclic steam operations in the past, indicating that CalGEM intended to revisit the moratorium on a field-by-field basis, but no further guidance has yet been received by us to date. Importantly, the moratorium on high-pressure cyclic steam injection did not impact existing production or previously approved permits and our plans and operations have not been materially impacted to date. In 2023, we drilled, and in 2024 we have plans to drill permitted wells in these thermal diatomite properties.

Historically, state regulators have overseen hydraulic stimulation operations as part of their oil and natural gas regulatory programs. However, from time to time, federal agencies have asserted regulatory authority over certain aspects of the process. In 2016, the EPA issued final regulations regarding, among other things, certain hydraulic stimulation activities involving the use of diesel fuels and standards for the capture of air emissions released during hydraulic stimulation. And while the BLM previously rescinded regulations imposing certain requirements on hydraulic fracturing on federal lands in 2017, the rescission is subject to ongoing legal challenge and the regulations may be reconsidered under the Biden Administration. Relatedly, the Biden Administration has released proposed rules mandating that operators maintain leak detection and repair plans for operations on federal or Native American leased land and, in November 2022, proposed a rule that would limit flaring from well sites on federal lands as well as allow the delay or denial of permits if the agency finds an operator's methane waste minimization plan insufficient. A final rule is scheduled for publication in the first quarter of 2024. The outcome of these rules could materially impact our operations in the Uinta basin, where as of December 31, 2023, approximately 16% of our proved reserves in Utah were located on federal lands and approximately 78% were located on tribal lands. In addition, from time to time legislation has been introduced before Congress that would provide for federal regulation of hydraulic stimulation and would require disclosure of the chemicals used in the stimulation process. If enacted, these or similar bills could result in additional permitting requirements for hydraulic stimulation operations as well as various restrictions on those operations. These permitting requirements and restrictions could materially impact our operations in the Uinta basin, including delays in operations at well sites and increased costs to make wells productive.

Water Resources

Oil and gas exploration and development activities can be adversely affected by the availability of water. Drought conditions, competing water uses and other physical disruptions to our access to water could adversely affect our operations. In recent years, California and Utah have experienced persistent and severe drought conditions. As a result water districts and the California state government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Various local governments in Utah have also implemented water restrictions. Water management, including our ability to recycle, reuse and dispose of produced water and our access to water supplies from third-party sources, in each case at a reasonable cost, in a timely manner and in compliance with applicable laws, regulations and permits, is an essential component of our operations. As such, any limitations or restrictions on wastewater disposal or water availability could have an adverse impact on our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, steam flooding and well drilling, completion and stimulation. We use water supplied from various local and regional sources, particularly for power plants and to support operations like steam injection in certain fields. While our production to date has not been materially impacted by restrictions on wastewater disposals or access to third-party water sources, we cannot guarantee that there may not be restrictions in the future.

Regulation of Health, Safety and Environmental Matters

The federal health, safety and environmental laws and regulations applicable to us and our operations include, among others, the following:

- Occupational Safety and Health Act ("OSHA"), which governs workplace safety and the protection of the safety and health of workers;
- Clean Air Act (the "CAA"), which restricts the emission of air pollutants from many sources through the imposition of air emission standards, construction and operating permitting programs and other compliance requirements;
- Clean Water Act (the "CWA"), which restricts the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands;
- The Oil Pollution Act of 1990, which amends and augments the CWA and imposes certain duties and liabilities related to the prevention of oil spills and damages resulting from such spills;
- Safe Drinking Water Act ("SDWA"), which, amongst other matters, regulates the drilling and operation of injection and disposal wells that manage produced water;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes strict, joint and several liability where hazardous substances have been released into the environment (commonly known as "Superfund");
- U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates the safe and secure transportation of energy, including, with some specific exceptions, natural gas pipelines;
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards, mandates for production of renewable fuels and other energy saving measures, which can indirectly affect demand for our products;
- National Environmental Policy Act ("NEPA"), which requires careful evaluation of the environmental impacts of oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste (broadly defined to include liquid and gaseous waste as well);
- DOI regulations, which impose requirements on oil and gas production activities on federal lands and establish liability for pollution cleanup and damages; and
- Endangered Species Act, which restricts activities that may affect endangered and threatened species or their habitats.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. The State of California imposes additional laws that are analogous to, and often more stringent than, the federal laws listed above. Among other requirements and restrictions, these laws and regulations:

- require the acquisition of various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection, enhanced oil recovery methods or waste disposal commences, or before facilities are constructed or put into operation;

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;
- impose, on federal, state and local jurisdiction lands, comprehensive environmental analyses, recordkeeping and reports with respect to operations including preparation of various environmental impact assessments for certain operations;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and control systems, and implementation of inspection, monitoring and repair programs to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, and require conservation and reclamation measures;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment in connection with drilling and production activities, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;
- limit or prohibit drilling activities on lands located within coastal, wilderness, wetlands, groundwater recharge or endangered species inhabited areas, and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources, and require the dedication of surface acreage for habitat conservation;
- establish waste management standards or require remedial measures to limit pollution from former operations, such as pit closure, reclamation and plugging and abandonment of wells or decommissioning of facilities;
- impose substantial liabilities for pollution resulting from operations or for preexisting environmental conditions on our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require notice to stakeholders of proposed and ongoing operations;
- impose energy efficiency or renewable energy standards on us or users of our products and require the purchase of allowances to account for our GHG emissions if we are unable to reduce our emissions below the California statewide maximum limit on covered GHG emissions;
- restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics; and
- impose taxes or fees with respect to the foregoing matters.

Except for the regulations described herein relating to our oil and gas operations, we believe that maintaining compliance with currently applicable health, safety and environmental laws and regulations is unlikely to have a material adverse impact on our business, financial condition, results of operations or cash flows. However, we cannot guarantee this will always be the case given the historical trend of increasingly stringent laws and regulations. We cannot predict how future laws and regulations, or the reinterpretation of existing laws and regulations, may impact our properties or operations.

Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, and operational interruptions or shutdowns, among other sanctions and liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and prospects. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties. For the year ended December 31, 2023, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures during 2024 or that will otherwise have a material impact on our financial position, results of operations or cash flows.

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

The potential threat of climate change due to human behaviors continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our E&P operations are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, with the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States and together with the U.S. Department of Transportation ("DOT"), implement GHG emissions limits on vehicles manufactured for operation in the United States.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, and restriction of GHG emissions, such as carbon dioxide and methane. For example, California, through the California Air Resources Board ("CARB") has implemented a cap-and-trade program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030. Covered entities must either reduce their GHG emissions or purchase allowances to account for such emissions. Separately, California has implemented low carbon fuel standard ("LCFS") and associated tradable credits that require a progressively lower carbon intensity of the state's fuel supply than baseline gasoline and diesel fuels. Recently, CARB proposed amendments to the LCFS program to include increasing 2030 carbon intensity targets from 20% to 30% and extending carbon intensity reduction targets to 90% by 2045. CARB has also promulgated regulations regarding monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production facilities.

In addition to the actions described above requiring California to achieve total economy-wide carbon neutrality by 2045, California has separately adopted a law requiring the use of 100% zero-carbon electricity within the state by 2045. Additionally, the Governor of California requested that the CARB analyze pathways to phase out oil extraction across the state by no later than 2045; however, CARB's 2022 Final Scoping Plan (the "2022 Final Scoping Plan"), the blueprint for the state's carbon neutrality goals, determined such a phase out was not feasible because of continued projected demand for fossil fuels in the transportation sector notwithstanding significant projected decreases in demand for fossil fuels for such uses by 2045. Notwithstanding this, CARB will continue to assess opportunities for phase down in its next five year scoping plan. The 2022 Final Scoping Plan also outlines a plan to phase out natural gas use in buildings, amongst other carbon emission reduction matters. We cannot predict how these various laws, regulations and orders may ultimately affect our operations. However, these initiatives could result in decreased demand for the oil, natural gas and NGLs that we produce, or otherwise restrict or prohibit our operations altogether in California, and therefore adversely affect our revenues and results of operations.

At the international level, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. Although the United States had withdrawn from the Paris Agreement, President Biden signed an executive order on his first day in office recommitting the United States to the agreement. In February 2021, the United States formally rejoined the Paris Agreement, and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at the 26th Conference of the Parties ("COP26") in Glasgow in November 2021, the United States and the European Union jointly announced the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including “all feasible reductions” in the energy sector. The following year, the United States announced in conjunction with the European Union and other partner countries that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. At COP28, hosted by the United Arab Emirates in December 2023, parties signed onto an agreement to transition “away from fossil fuels in energy systems in a just, orderly, and equitable manner” and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set. The full impact of these actions is uncertain at this time and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon our operations.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change-related pledges made by certain candidates for public office. These have included promises to pursue actions to limit emissions and curtail the production of oil and gas, such as banning new leases for production of minerals on federal properties. On January 20, 2021, President Biden issued an executive order calling for increased regulation of methane emissions from the oil and gas sector. Subsequently, on January 27, 2021, President Biden issued an executive order that called for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across agencies and economic sectors. Other actions that could be pursued by President Biden may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as other GHG emissions limitations for oil and gas facilities.

Litigation risks are also increasing, as a number of parties have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but withheld material information from their investors or customers by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, in October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corp. released a finalized set of principles guiding financial institutions with $100 billion or more in assets on the management of physical and transition risks associated with climate change. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or E&P activities. Additionally, in March 2022, the Securities and Exchange Commission (“SEC”) released a proposed rule that would establish a framework for the reporting of climate risks, targets, and metrics. We cannot predict the final form and substance of the rule and its requirements. The ultimate impact of the rule on our business is uncertain and, upon finalization may result in additional costs to comply with any such disclosure requirements alongside increased costs of and restrictions on access to capital. Separately, the SEC has also announced that it is scrutinizing existing climate-changed related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer’s climate disclosures are misleading, deceptive or deficient. Such agency action could increase the potential for private litigation.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from oil and natural gas producers such as ourselves or otherwise restrict the areas in which we may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or erode value for, the oil and natural gas that we produce. Additionally, political, litigation, and financial risks may result in our restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing our ability to continue to operate in an economic manner.

Moreover, climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our operations, as well as those of our operators and their supply chains. Such physical risks may result in damage to our facilities or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact our supply chain or infrastructure on which we rely to produce or transport our products. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

For more information, please see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**—***Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change the requirements governing our operations, including the permitting approval process for oil and gas exploration, extraction, operations and production activities; well stimulation and other enhanced production techniques; and fluid injection or disposal activities, any of which could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy and plans" and "—Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas E&P activities, and reduce demand for the oil and natural gas we produce."***

Human Capital Resources

As of December 31, 2023, we had 1,282 employees, all of whom are located in the United States. Of those, 925 employees are employed in our CJWS business, and the remainder are corporate or employed in our E&P business in California. Currently, none of our employees are covered under collective bargaining or union agreements. We also utilize the service of third-party contractors throughout our operations.

We believe that developing the best talent, promoting a safe and healthy workplace, providing an inclusive culture, and supporting the well-being of our employees and local communities are critical to the Company's success. The Compensation Committee of the Board of Directors has oversight responsibilities for the Company's human capital management policies, processes and practices, including those related to workforce diversity, pay equity, compensation and incentive structures, employee recruitment, retention and development, and succession planning.

Culture, Core Values and Employee Engagement

We are committed to the well-being of our employees and strive to foster a corporate culture that is reflective of our core values. We aim to provide development opportunities and financial rewards so that our employees are engaged and focused on providing safe, affordable and reliable energy for the people of California.

We believe that fair and equitable pay is an essential element of any successful organization and we reward our talented employees for their hard work, qualities, experience and passion. We strive to offer comprehensive and competitive benefits that support the health and well-being of our employees and their families, while consistently offering opportunities for professional growth and development in line with our mission. In addition, the incentive compensation program for our entire workforce, including our executive team, is tied to company performance on safety and environmental responsibility, as well as financial stewardship.

We proactively work to help our employees stay fully engaged and empowered to achieve their potential and we are committed to attracting, developing and retaining a highly qualified and value-focused workforce. Our engagement approach centers on transparency and accountability and we use a variety of channels as part of our efforts to facilitate open, direct and honest communication, including open forums with executives through periodic town hall meetings and continuous opportunities for discussion and feedback between employees and managers, including performance conversations and reviews. We also survey our employees periodically to assess engagement levels and satisfaction drivers. The results of the engagement surveys are reviewed by senior management and the

Board of Directors and then communicated to our employees along with a company action plan to address concerns identified by the surveys.

We strive to promote a workplace culture of inclusiveness, dignity and respect for all employees as well as a safe, appropriate, and productive work environment. Accordingly, we prohibit harassment and discrimination at our work facilities, as well as off-site, including business trips, business functions and company-sponsored events. In particular, our Code of Conduct prohibits any form of degrading, offensive, or intimidating conduct based on any characteristic protected by applicable law, whether race, color, ethnicity, national origin, ancestry, citizenship status, sex, gender identity and/or expression, sexual orientation, mental disability, physical disability, medical condition, genetic information, age, parental status or pregnancy, marital status, religion, religious creed, military or veteran status.

We value our workforce reflecting the broad spectrum of cultural, demographic and philosophical differences of the communities where we operate, and work to foster a culture that supports and protects inclusivity. As an example of this, we are proud to have attracted and retained highly talented and experienced women to our workforce in positions across our organization. Currently, our Board of Directors is 29% women, our executive leadership team is 25% women, and Berry's total workforce is approximately 9% women, with the E&P segment being 19% women and CJWS being 5% women.

Safe and Healthy Workplace

We promote a safety-first culture. Health and safety considerations are an integral part of our day-to-day operations and incorporated into the decision-making process for our Board of Directors, management and all employees. Meeting meaningful HSE organizational metrics, including with respect to health and safety and spill prevention, is a part of our incentive programs for our entire workforce. Our businesses maintain health and safety training programs designed to support a safety-first culture and allow personnel to develop appropriate skills and understanding of our HSE policies. Routine and periodic drills are conducted as part of our employees' education and safety training.

Corporate Information

Our principal executive office is located at 16000 N. Dallas Pkwy, Ste. 500, Dallas, Texas 75248 and our telephone number at that address is (214) 453-2920. Our web address is *www.bry.com*. We make certain filings with the SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. The SEC maintains an internet site, http://*www.sec.gov,* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. We make such filings available free of charge through our website as soon as reasonably practicable after they are filed with the SEC. In addition to reports filed or furnished with the SEC, we publicly disclose material information from time to time in press releases, at annual meetings of shareholders, in publicly accessible conferences and investor presentations, and through our website. Information contained in or accessible through our website is not, and should not be deemed to be, part of this report.

Item 1A. Risk Factors

If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only risks and uncertainties we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may ultimately materially affect our business.

Summary Risk Factors

The exploration, development and production of oil and natural gas involve highly regulated, high-risk activities with many uncertainties and contingencies that could adversely affect our business, financial condition, results of operations and cash flows. The risks and uncertainties described below are among the items we have identified that could materially adversely affect our business, financial condition, results of operations and cash flows. Before you invest in our common stock, you should carefully consider the risk factors referenced below and as more fully described in "Item 1A. Risk Factors" in this Annual Report.

Risks Related to Our Operations and Industry

- There are significant uncertainties with respect to obtaining permits for oil and gas activities in Kern County, where all of our California operations are located, which could impact our financial condition and results of operations.
- Attempts by the California state government to restrict the production of oil and gas could negatively impact our operations and result in decreased demand for fossil fuels.
- Our ability to be profitable and maintain our financial condition is highly dependent on commodity prices.
- The conflict in Ukraine, the Israel-Hamas conflict, related price volatility and geopolitical instability could negatively impact our business.
- The marketability of our production is dependent upon the availability of transportation and storage facilities, most of which we do not control.
- Our oil and gas reserves and related future net cash flows may prove to be lower than estimated.
- Unless we replace oil and natural gas reserves, our future reserves and production will decline.
- Drilling for and producing oil and natural gas involves many uncertainties and risks that are beyond our control.
- We may not drill our identified sites at the times we scheduled or at all.
- Competition in the oil and natural gas industry is intense.
- We may be unable to make attractive acquisitions or successfully complete acquisitions and integrate acquired businesses or assets or enter into attractive joint ventures.
- We are dependent on our cogeneration facilities to produce steam for our operations. Operational issues and inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise could restrict access to commodity markets.
- Most of our operations are in California, much of which is conducted in areas that may be at risk of damage from fire, mudslides, earthquakes or other natural disasters.
- We may incur substantial losses and be subject to substantial liability claims as a result of catastrophic events.
- We may be involved in legal proceedings that could result in substantial liabilities.
- The loss of senior management or technical personnel could adversely affect operations.
- Information technology and operational failures and cyberattacks could significantly affect our business, financial condition, results of operations and cash flows.
- Increasing attention to ESG matters, including climate-related reporting obligations, may impact our operations and our business.

Risks Related to Our Financial Condition

- We may not be able to use a portion of our net operating loss carryforwards and other tax attributes to reduce our future U.S. federal and state income tax obligations, which could adversely affect our cash flows.
- Our business requires continual capital expenditures that we may be unable to fund.
- Inflation could adversely impact our ability to control our costs.
- Our hedging activities limit our ability to realize the full benefits of increases in commodity prices and may not fully protect us against the price decreases.
- Our existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities and our lenders could reduce capital available to us for investment.
- We may not be able to generate sufficient cash to service our indebtedness.
- Declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in write-downs of the carrying amounts of our assets.
- We have significant concentrations of credit risk with our customers.

Risks Related to Regulatory Matters

- Our business is highly regulated and governmental authorities can delay or deny required permits and approvals, or change the requirements governing our operations.
- Potential future legislation may generally affect the taxation of natural gas and oil exploration and development companies and may adversely affect our operations and cash flows.
- Derivatives legislation and regulations could have an adverse effect on our ability to use derivative instruments to reduce the risks associated with our business.
- Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas E&P activities, and reduce demand for the oil and natural gas we produce.
- The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.

Risks Related to our Capital Stock

- There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.
- Our significant stockholders and their affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in the Certificate of Incorporation could enable our significant stockholders to benefit from corporate opportunities that might otherwise be available to us.
- Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.
- The payment of dividends will be at the discretion of our Board of Directors.
- We may issue preferred stock, the terms of which could adversely affect the voting power or value of our common stock.
- We are no longer an "emerging growth company," and are no longer able to take advantage of reduced disclosure requirements. Due to losing emerging growth company status, we expect to incur additional costs.
- Failure to achieve and maintain effective internal control over financial reporting in accordance with the standards of Section 404 of the Sarbanes-Oxley Act could have a material adverse effect on our business and share price.
- Certain provisions of our Certificate of Incorporation and Bylaws may make it difficult for stockholders to change the composition of our Board of Directors and may discourage, delay or prevent a merger or acquisition.
- Our Certificate of Incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders.

Risks Related to Our Operations and Industry

The risks and uncertainties described below are among the items we have identified that could materially adversely affect our business, production, strategy, growth plans, acquisitions, hedging, reserves quantities or value, operating or capital costs, financial condition, results of operations, liquidity, cash flows, our ability to meet our capital expenditure plans and other obligations and financial commitments, and our plans to return capital.

There are significant uncertainties with respect to obtaining permits for oil and gas activities in Kern County, where all of our California operations are located, which could impact our financial condition and results of operations.

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 CEQA and/or 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 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 (the "Kern County EIR"). However, the Kern County EIR was legally challenged in 2020, with a recent decision handed down on March 7, 2024, directing Kern County to prepare a revised EIR that corrects certain CEQA violations, circulate the revised EIR for public review and comment, and prepare and publish responses to any comments received before certifying the revised EIR. The suspension of the Kern County EIR, and the reviewing and approving of permits pursuant to the Kern County zoning ordinance, remains in effect. Accordingly, our ability to rely on the Kern County 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, throughout 2023 and year to date in 2024, neither we nor any other operator received permits to drill new wells using the Kern County EIR to demonstrate CEQA compliance. In fact, since January 2023, relatively few permits to drill new wells in California have been issued to any oil producer.

Currently, as a result of the Kern County EIR legal challenges, in order to obtain permits for drilling new wells in Kern County, we must demonstrate compliance with CEQA to CalGEM through means other than the Kern County EIR. Berry has a separate environmental impact analysis covering certain assets, and in the past we have have been successful in obtaining permits to drill new wells in the covered areas. However, we began to experience delays in the issuance of drill permits in those areas during the third quarter of 2023, which we believe is due to changes in CalGEM's CEQA review process. Additionally, in the third quarter of 2023, we started to experience delays in the approval process for workover and sidetrack permits as well, which we believe is also due to changes in CalGEM's review process. While the timing of receiving these permits has recently been inconsistent, we have continued to receive permits.

Approximately 95% of our production in 2023 came from our base production, with the remainder from 33 wells drilled in California during the year (five new wells and 28 sidetracks), workovers and other activities related to existing wellbores, and production acquired from the Macpherson Acquisition. Similar to 2023, our 2024 plans assume that we will not receive permits to drill new wells and instead focus on drilling sidetracks and working over existing wells. We also expect to benefit from a full year of production from the assets acquired in the Macpherson Acquisition and other bolt-on acquisitions at the end of 2023, which should help keep our production essentially flat in 2024. We currently have sufficient permits in hand that should allow us to maintain sidetrack activity through around July 2024 and a continuous workover campaign for approximately the first half of the year. We are in the process of obtaining the remaining permits needed to support our 2024 plans, while also working to obtain additional permits to support future plans. The permitting applications necessary to hold production flat for the full year 2024, none of which are dependent on the Kern County EIR, have been submitted to CalGEM and are pending approval.

Separately, in February 2021, the Center for Biological Diversity filed suit against CalGEM alleging that its reliance on the Kern County EIR for oil and gas decisions violates CEQA, and that an independent environmental impact review in compliance with CEQA is required by CalGEM before the agency can issue oil and gas permits and approvals. Most recently, the Alameda County Superior Court denied CalGEM's motion for judgment on the pleadings and the lawsuit remains ongoing. We cannot predict its ultimate outcome or whether it could result in changes to the requirements for demonstrating compliance with CEQA and the permitting process, even if the Kern County EIR is ultimately deemed sufficient and reinstated. The potential impact of this and potentially future litigation contributes to the uncertainty with respect to our ability to timely obtain the permits and approvals needed to conduct our operations.

If we are unable to obtain the required permits and approvals needed to conduct our operations on a timely basis or at all our financial condition, results of operations and prospects could be adversely and materially impacted. At this time, we expect that greater than 90% of our planned 2024 production will come from our base production, with the remainder from workovers, sidetracks and other activities related to existing wellbores. As a result of the Kern County EIR legal challenges and other related permitting uncertainties, our current capital budget for 2024 has been prepared on the assumption that no additional permits for new wells will be issued in 2024 in areas for which CEQA analysis has not already been completed separate from the currently suspended Kern County EIR.

Based on our reserves as of December 31, 2023, if we are unable to obtain new well drill permits through the Kern County EIR or other avenues for CEQA compliance through 2024, it could result in the loss of some amount of the proved undeveloped reserves that expire by December 31, 2025. In addition, any changes to the CEQA compliance requirements or the other conditions and requirements for permit issuance or renewal, including the imposition of new or more stringent environmental reviews or stricter operational or monitoring requirements, or a prohibition on the issuance of new permits for oil and has activities in Kern County or California as a whole, would have an adverse and material effect on our financial condition, results of operations and prospects. For additional information, see "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters."

Attempts by the California state government to restrict the production of oil and gas could negatively impact our operations and result in decreased demand for fossil fuels within the states where we operate.

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. A combination of federal, state and local laws and regulations govern most aspects of our activities in California and federal, state and local agencies may assert overlapping authority to regulate in these areas. 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 on the industry in the past has resulted, and in the future could result, in increased costs, and consequently has had an adverse effect upon 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.

Additionally, the California state government recently has taken several actions that could adversely impact future oil and gas production and other activities in the state. For example:

- In November 2019, the State Department of Conservation issued a press release announcing four actions by CalGEM: (1) a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators; (2) a review and update of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the California State Legislature in 2019 (discussed above); (3) a performance audit of CalGEM's permitting processes for issuing WST (also known as hydraulic stimulation, hydraulic fracturing or fracking) permits and project approval letters ("PALs") for underground injection activities by the State Department of Finance; and (4) an independent review of the technical content of pending WST and PAL applications by Lawrence Livermore National Laboratory. In January 2020, CalGEM issued a formal notice to operators, including us, that they had issued restrictions imposing the previously announced moratorium to prohibit new underground oil-extraction wells from using high-pressure cyclic steaming process. The moratorium on permitting for new high–pressure cyclic steam wells and restrictions on WST remains in effect.

- In October 2020, the Governor of California issued an executive order that established a state goal to conserve at least 30% of California's land and coastal waters by 2030 and directed state agencies to implement other measures to mitigate climate change and strengthen biodiversity. At this time, we cannot predict the potential future actions that may result from this order or how such may potentially impact our operations.

- In September 2022, the Governor of California signed Senate Bill No. 1279 into law, codifying an executive order previously issued by the Governor's Office requiring the state to achieve carbon neutrality by 2045. In addition, the Governor of California previously issued an executive order that established several goals and directed several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: (1) phasing out the sale of emissions-producing vehicles; (2) developing strategies for the closure and repurposing of oil and gas facilities in California; and (3) calling on the California State Legislature to enact new laws prohibiting hydraulic fracturing in the state by 2024. In February 2024, CalGEM issued a proposed regulation to formally end hydraulic fracturing in the state, restricting approval of any permit applications to conduct well stimulation treatments (which includes hydraulic fracturing). We currently do not perform any hydraulic fracturing in California and our near term plans do not include the development of assets requiring hydraulic fracturing.

- In September 2022, the Governor of California signed into law Senate Bill No. 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 effective January 1, 2023. On January 6, 2023, CalGEM's emergency regulations to support implementation of Senate Bill No. 1137 were approved by the Office of Administrative Law and final regulations were published. The regulations include applicable requirements of notice to property owners and tenants regarding the work performed and offering the sampling of test water wells or surface water before and after drilling; the contents of required notices for new production facilities; the annual submission of a sensitive receptor inventory and sensitive receptor map and the contents and format of the same; and the requirements of statements where operators have determined a location not to be within a health protection zone. Additional provisions of Senate Bill No. 1137 would also require pollution controls for existing wells and facilities within the same 3,200-foot setback area. Senate Bill No. 1137 is currently stayed pending a vote of the California General Election in November 2024. We continue to assess the impacts of Senate Bill No. 1137 and CalGEM's regulations, but we currently estimate that approximately 10% of our overall proved reserves 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.

- In October 2023, the Governor of California signed into law AB 1167, which 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 being acquired. 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 Governor of California called for further legislative changes to the new requirements to mitigate the potential risk of an increase in the number of orphaned wells becoming state liabilities following the implementation of the law. However, to date, no further action has been taken. To the extent the law is implemented as written, we could face increased bonding or other financial-assurance related costs in connection with new acquisitions, or may find it infeasible to pursue certain acquisitions because of such costs.

The clear trend in California is to impose increasingly stringent restrictions on oil and natural gas activities. We cannot predict what actions the Governor of California, the California Legislature, or state agencies may take in the future, but we could face increased compliance costs, delays in obtaining the approvals necessary for our operations, exposure to increased liability, or other limitations as a result of future actions by these parties. Moreover, new developments resulting from the current and future actions of these parties could also materially and adversely affect our ability to operate, successfully execute drilling plans, or otherwise develop our reserves. Accordingly, recent and future actions by the Governor of California, the California Legislature, and state agencies could materially and adversely affect our business, results of operations, and financial condition.

The Climate Corporate Data Accountability Act and Climate-Related Financial Risk Act both impose climate-related reporting obligations including GHG emissions which could result in additional costs for compliance, restrictions on our access to capital, and increased litigation and reputational risk.

The Governor of California signed the Climate Corporate Data Accountability Act ("CCDAA"), or SB 253, into law on October 7, 2023, alongside the Climate-Related Financial Risk Act ("CRFRA"), or SB 261. The CCDAA requires both public and private U.S. companies that are "doing business in California" and that have a total annual revenue of $1 billion to publicly disclose and verify, on an annual basis, Scope 1, 2 and 3 GHG emissions. The CRFRA requires the disclosure of a climate-related financial risk report (in line with the Task Force on the Climate-related Financial Disclosures recommendations or equivalent disclosure requirements under the International Sustainability Standards Board's climate-related disclosure standards) every other year for public and private companies that are "doing business in California" and have total annual revenue of $500 million. Reporting under both laws would begin in 2026, though the Governor of California has directed further consideration of the implementation deadlines for each of the laws. Both laws have been challenged in federal court. Currently, we are still assessing the potential impacts of these laws; however, implementation may result in additional costs to comply with these disclosure requirements as well as increased costs of and restrictions on access to capital if our disclosures are not perceived as meeting applicable third-party verification of GHG emissions and climate-related criteria. Separately, enhanced climate-related disclosure requirements could lead to reputational or other harm to our relationships with customers, regulators, investors or other stakeholders. In addition, we may also face increased litigation risks arising from enhanced climate-related disclosure requirements relating to alleged damages resulting from GHG emissions from our operations, statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent complexity of multiple, overlapping GHG reporting regulations with respect to calculating and reporting GHG emissions.

Our ability to operate profitably and maintain our business and financial condition are highly dependent on commodity prices, which historically have been very volatile and are driven by numerous factors beyond our control. If oil prices were to significantly decline for a prolonged period of time, our business, financial condition and results of operations may be materially and adversely affected.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, value of our reserves, access to capital and future rate of growth, among other factors. However, the price we receive for our oil and natural gas production depends on numerous factors beyond our control, including not limited to, the following:

- overall domestic and global political and economic conditions, including the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict, including the ongoing conflict in Ukraine and the Israel-Hamas conflict, rising inflation levels and government efforts to reduce inflation or a prolonged recession;
- changes in global supply and demand for oil and natural gas, including changes in demand resulting from general and specific economic conditions relating to the business cycle and other factors;
- the actions of OPEC and/or OPEC+;
- the price and quantity of imports of foreign oil and natural gas;
- the level of global oil and natural gas E&P activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- domestic and foreign governmental legislative efforts, executive actions and regulations, including environmental regulations, climate change regulations and taxation;
- the effect of energy conservation efforts;
- stockholder activism or activities by non-governmental organizations to limit certain sources of capital for the energy sector or restrict the exploration, development and production of oil and gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Historically, the markets for oil and natural gas have been extremely volatile and will likely continue to be volatile in the future. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Global economic growth drives demand for energy from all sources, including fossil fuels. When the U.S. and global economies experience weakness, demand for energy will decline with accompanying declines in commodity prices; similarly, when growth in global energy production outstrips demand, the excess supply results in commodity price declines.

Concerns over global economic conditions, energy costs, geopolitical issues, such as the ongoing conflict in Ukraine and the Israel-Hamas conflict, inflation, the availability and cost of credit and slow economic growth in the United States have in the past contributed to significantly reduced economic activity and diminished expectations for the global economy. If the economic climate in the United States or abroad deteriorate, worldwide demand for petroleum products could further diminish, which could impact the price at which oil, natural gas and NGLs from our properties are sold, affect our level of operations and ultimately materially adversely impact our results of operations, financial condition and free cash flow.

Additionally, although the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. Refer to Item 7—“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Business Environment and Market Conditions.”

Past declines in pricing, and any declines that may occur in the future, can be expected to adversely affect our business, financial condition and results of operations. Such declines adversely affect well and reserve economics and may reduce the amount of oil and natural gas that we can produce economically, resulting in deferral or cancellation of planned drilling and related activities until such time, if ever, as economic conditions improve sufficiently to support such operations. Any extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Global geopolitical tensions and related price volatility and geopolitical instability could negatively impact our business.

In late February 2022, Russia launched significant military action against Ukraine. The conflict has caused, and could intensify, volatility in the prices of natural gas, oil and NGLs, and the extent and duration of the military action, sanctions and resulting market disruptions have been significant and could continue to have a substantial impact on the global economy and our business for an unknown period of time. There is evidence that the increase in crude oil prices during the first half of calendar year 2022 was partially due to the impact of the conflict between Russia and Ukraine on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Alternatively, a cessation of the hostilities between Russia and Ukraine as a result of a negotiated withdrawal or otherwise could cause commodity prices to decline, which would reduce the revenues we receive for our oil and gas production.

Additionally, on October 7, 2023, Hamas, a U.S. designated terrorist organization, launched a series of coordinated attacks from the Gaza Strip onto Israel. On October 8, 2023, Israel formally declared war on Hamas, and the armed conflict is ongoing as of the date of this filing. Hostilities between Israel and Hamas could escalate and involve surrounding countries in the Middle East. Although the length, impact and outcome of the military conflicts between Ukraine and Russia and between Israel and Hamas are highly unpredictable, these conflicts could lead to significant market and other disruptions, including significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, political and social instability and other material and adverse effects on macroeconomic conditions. It is not possible at this time to predict or determine the ultimate consequence of these regional conflicts. Any such volatility and disruptions may also magnify the impact of the other risks described in this “Risk Factors” section.

The marketability of our production is dependent upon transportation and storage facilities and other facilities, most of which we do not control, and the availability of such transportation and storage capabilities. If we are unable to access such facilities on commercially reasonable terms, our operations would likely be interrupted, our production could be curtailed, and our revenues reduced, among other adverse consequences.

The marketing of oil, natural gas and NGLs production depends in large part on the availability, proximity and capacity of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. Storage and transportation capacity for our production is limited and may become unavailable on commercially reasonable terms or at all. For example, storage and transportation capacity became scarce during the second quarter of 2020 due to the unprecedented dual impact of a severe global oil demand decline coupled with a substantial increase in supply. As traditional tanks filled, large quantities of oil were being stored in offshore tankers around the world, including off the coast of California. Where storage was available, such as offshore tankers, storage costs increased sharply. The potential risk remains that storage for oil may be unavailable and our existing capacity may be insufficient to support planned production rates in the event of another deterioration in demand or a supply surge or both.

Moreover, if the imbalance between supply and demand and the related shortage of storage capacity worsen, the prices we receive for our production could deteriorate and could potentially even become negative. Additionally, if we were unable to obtain the needed storage capacity, we could be forced to shut in a significant amount of our California production, which could have a material adverse effect on our financial condition, liquidity and operational results. If we are forced to shut in production, we would incur additional costs to bring the associated wells back online. While production is shut in, we would likely incur additional costs and operating expenses to, among other things, maintain the health of the reservoirs, meet contractual obligations and protect our interests, without the associated revenue. Additionally, depending on the duration of the shut-in, and whether we have also shut in steam injection for the associated reservoirs rather than incur those costs, the wells may not, initially or at all, come back online at similar rates to those at the time of shut-in. Depending on the duration of the steam injection shut-in time, and the resulting inefficiency and economics of restoring the reservoir to its energetic and heated state, our proved reserve estimates could be decreased and there could be potential additional impairments and associated charges to our earnings. A reduction in our reserves could also result in a reduction to our borrowing base under the 2021 RBL Facility and our liquidity. The ultimate significance of the impact of any production disruptions, including the extent of the adverse impact on our financial and operational results, will be dictated by the length of time that such disruptions continue, which will in turn depend on how long storage remains filled and unavailable to us, which is largely unpredictable and based on factors outside of our control.

In addition to the constraints we may face due to storage capacity shortages, the volume of oil and natural gas that we can produce is subject to limitations resulting from pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, and physical damage to the gathering, transportation, storage, processing, fractionation, refining or export facilities that we utilize. The curtailments arising from these and similar circumstances may last from a few days to several months or longer and, in many cases, we may be provided only limited, if any, advance notice as to when these circumstances will arise and their duration. Any such shut-in or curtailment, or any inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be different from estimates.

Estimation of reserves and related future net cash flows is a partially subjective process of estimating accumulations of oil and natural gas that includes many uncertainties. Our estimates are based on various assumptions, which may ultimately prove to be inaccurate, including:

- the similarity of reservoir performance in other areas to expected performance from our assets;
- the quality, quantity and interpretation of available relevant data;
- commodity prices;
- production, operating costs, taxes and costs related to GHG regulations;
- development costs;
- the effects of government regulations, including our ability to obtain permits in a timely manner, or at all, for proved undeveloped reserves; and
- future workover and asset retirement costs.

Misunderstanding these variables, inaccurate assumptions, changed circumstances or new information could require us to make significant negative reserves revisions.

We currently expect improved recovery, extensions and discoveries and, potentially acquisitions, to be our main sources for reserves additions. However, factors such as the availability of capital, geology, government regulations and our ability to obtain permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions. Any material inaccuracies in our reserves estimates could materially affect the net present value of our reserves, which could adversely affect our borrowing base and liquidity under the 2021 RBL Facility, as well as our results of operations.

Unless we replace oil and natural gas reserves, our future reserves and production will decline.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Success requires us to deploy sufficient capital to projects that are geologically and economically attractive which is subject to the capital, development, operating and regulatory risks already discussed above under the heading "*—Our business requires continual capital expenditures. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves or production. Our capital program is also susceptible to risks, including regulatory and permitting risks, that could materially affect its implementation.*" For example, beginning in the second quarter of 2022, we adjusted our capital development program due to the delays in permit issuance and insufficient permit inventory. We have continued to implement alternative capital development programs in 2023 and 2024 as a result of continued permitting issues.

See "—*There are significant uncertainties with respect to obtaining permits for oil and gas activities in Kern County, where all of our California operations are located, which could impact our financial condition and results of operations*." In addition, if we are unable to obtain new well drill permits through 2024, it will likely result in the loss of some amount of the proved undeveloped reserves that expire by December 31, 2025, and additional reserves in years beyond 2025 if permitting issues are not ultimately favorably resolved. Although we benefited from production associated with acquisitions in 2023, such as the Macpherson Acquisition, there is no certainty that we will be able to continue to identify or complete attractive acquisitions. It is also possible that lower-than-expected demand and prices for commodities in the future could materially and adversely affect our future planned capital expenditures, such as our reductions in planned capital expenditures in 2020 in response to the effects of COVID-19 and the actions of OPEC+. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

Drilling for and producing oil and natural gas involves many uncertainties that could adversely affect our results.

The success of our development, production and acquisition activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production or may result in a downward revision of our estimated proved reserves due to:

- poor production response;
- ineffective application of recovery techniques;
- increased costs of drilling, completing, stimulating, equipping, operating, maintaining and abandoning wells;
- delays or cost overruns caused by equipment failures, accidents, environmental hazards, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes and other matters; and
- misinterpretation of geophysical and geological analyses, production data and engineering studies.

Additional factors may delay or cancel our operations, including:

- delays due to regulatory requirements and procedures, including unavailability or other restrictions limiting permits and limitations on water disposal, emission of GHGs, steam injection and well stimulation, such as California's recent limitations on cyclic steaming above the fracture gradient;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, qualified personnel or supplies including water for steam used in production or pressure maintenance;
- delays in access to production or pipeline transmission facilities; and
- power outages imposed by utilities which provide a portion of our electricity needs in order to avoid fire hazards and inspect lines in connection with seasonal strong winds, which have begun to occur recently and may impact our operations.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to property, reserves and equipment, pollution, environmental contamination and regulatory penalties.

We may not drill our identified sites at the times we scheduled or at all.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. Legislative and regulatory developments, such as California's recently adopted setback rules, could prevent us from planned drilling activities. Additionally, as discussed under "—*There are significant uncertainties with respect to obtaining permits for oil and gas activities in Kern County, where all of our California operations* *are located, which could impact our financial condition and results of operations*," new regulations and legislative activity could result in a significant delay or decline in, and/or the incurrence of additional costs for, the approval of the permits required to develop our properties in accordance with our plans. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. Accordingly, we cannot guarantee that these prospective drilling locations or any other drilling locations we have identified will ever be drilled or if we will be able to economically produce oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented approximately 3% of our total net acreage at December 31, 2023. Based on our reserves as of December 31, 2023, if we are unable to obtain permits for new wells through 2024, it will likely result in the loss of some amount of the proved undeveloped reserves that expire by December 31, 2025.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.

Our future success will depend on our ability to evaluate, select and acquire suitable properties, market our production and secure skilled personnel to operate our assets in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ greater financial, technical and personnel resources than we do.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses or assets or enter into attractive joint ventures, and any inability to do so may disrupt our business and hinder our ability to grow.

There is no guarantee we will be able to identify or complete attractive acquisitions. In July 2023, we announced the Macpherson Acquisition, which closed in September 2023, and we completed the acquisition of a small, highly synergistic additional working interest in Kern County, California in December 2023. Our capital expenditure budget for 2024 does not allocate any specific amounts for new acquisitions of oil and natural gas properties. If we make additional acquisitions, we would need to use cash flows, seek additional capital, or reallocate funds from other budgeted uses, all of which are subject to uncertainties discussed in this section. Competition may also increase the cost of, or cause us to refrain from, completing acquisitions. Our debt arrangements impose certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness. See "—Our existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities." In addition, the success of completed acquisitions will depend on our ability to integrate effectively the acquired business into our existing operations, may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources.

We may be unable to successfully integrate the business acquired in the Macpherson Acquisition or realize the anticipated benefits of the Macpherson Acquisition.

The combination of two independent businesses is complex, costly and time consuming, and we have been and will be required to devote management attention and resources to integrating Macpherson Energy's business practices and operations into ours. Potential difficulties that we may encounter as part of the integration process include the following:

- our inability to successfully combine the business of Macpherson Energy in a manner that permits us to achieve, on a timely basis or at all, the enhanced revenue opportunities and cost savings and other benefits anticipated to result from the Macpherson Acquisition;
- complexities associated with managing the combined businesses, including difficulty addressing possible differences in operational philosophies and the challenge of integrating complex systems, technology, networks and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees and other constituencies;
- the assumption of contractual obligations with less favorable or more restrictive terms; and

- potential unknown liabilities and unforeseen increased expenses or delays associated with the acquisition.

In addition, we and Macpherson Energy have previously operated independently. It is possible that the integration process could result in:

- diversion of the attention of our management; and
- the disruption of, or the loss of momentum in, our ongoing businesses or inconsistencies in standards, controls, procedures and policies.

Any of these issues could adversely affect our ability to maintain relationships with customers, suppliers, employees and other constituencies or achieve the anticipated benefits of the Macpherson Acquisition, or could reduce our earnings or otherwise adversely affect our business and financial results.

We are dependent on our cogeneration facilities to produce steam for our operations. Contracts for the sale of surplus electricity, economic market prices and regulatory conditions affect the economic value of these facilities to our operations.

We are dependent on four cogeneration facilities that, combined, provide approximately 10% of our steam capacity and approximately 43% of our field electricity needs in California at a discount to market rates. To further offset our costs, we sell surplus power to California utility companies produced by certain of our cogeneration facilities under long-term contracts. Should we lose, be unable to renew on favorable terms, or be unable to replace such contracts, we may be unable to realize the cost offset currently received. Our ability to benefit from these facilities is also affected by our ability to consistently generate surplus electricity and fluctuations in commodity prices. Furthermore, market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and any corresponding increase in the price of steam could significantly impact our operating costs. If we were unable to find new or replacement steam sources, lose existing sources or experience installation delays, we may be unable to maximize production from our heavy oil assets. If we were to lose our electricity sources, we would be subject to the electricity rates we could negotiate. For a more detailed discussion of our electricity sales contracts, see "Items 1 and 2. Business and Properties—Operational Overview—Electricity."

Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

We operate primarily in California, which is one of the most heavily regulated states in the United States with respect to oil and gas operations. This geographic concentration disproportionately affects the success and profitability of our operations exposing us to local price fluctuations, changes in state or regional laws and regulations, political risks, limited acquisition opportunities where we have the most operating experience and infrastructure, limited storage options, drought conditions, and other regional supply and demand factors, including gathering, pipeline and transportation capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. We discuss such specific risks to our California operations in more detail elsewhere in this section and in Part I, Item 1 and 2. "Business and Properties—Regulatory Matters" in this Annual Report.

Most of our operations are in California, much of which is conducted in areas that may be at risk of damage from fire, mudslides, earthquakes, floods or other natural disasters or extreme weather events.

We currently conduct operations in California near known wildfire and mudslide areas and earthquake fault zones. A future natural disaster, or extreme weather event, such as a fire, mudslide, flood, drought or an earthquake, could cause substantial interruption and delays in our operations, damage or destroy equipment, prevent or delay transport of our products and cause us to incur additional expenses, which would adversely affect our business, financial condition and results of operations. In addition, our facilities would be difficult to replace and would require substantial lead time to repair or replace. For example, in December of 2022, severe winter storms caused operational challenges, production downtime, and much higher natural gas prices in California. Extreme, adverse weather conditions, including flooding in the first quarter of 2023 impacted our operations and production levels. These events could occur with greater frequency as a result of the potential impacts from climate change. The insurance we maintain against earthquakes, mudslides, fires, floods and other natural disasters would not be adequate to cover a total loss of our facilities, may not be adequate to cover our losses in any particular case and may not continue to be available to us on acceptable terms, or at all.

Operational issues and inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise could restrict access to markets for the commodities we produce.

Our ability to market our production of oil, gas and NGLs depends on a number of factors, including the proximity of production fields to pipelines, refineries and terminal facilities, competition for capacity on such facilities, damage, shutdowns and turnarounds at such facilities and their ability to gather, transport or process our production. If these facilities are unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely, and expect to rely in the future, on third-party facilities for services such as storage, processing and transmission of our production. Our plans to develop and sell our reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. If our access to markets for commodities we produce is restricted, our costs could increase and our expected production growth may be impaired.

We may incur substantial losses and be subject to substantial liability claims as a result of catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our oil and natural gas E&P activities, are subject to risks such as fires, explosions, oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment, equipment failures and industrial accidents. We are exposed to similar risks indirectly through our customers and other market participants such as refiners. Other catastrophic events such as earthquakes, floods, mudslides, fires, droughts, contagious diseases, terrorist attacks and other events that cause operations to cease or be curtailed may adversely affect our business and the communities in which we operate. For example, utilities have begun to suspend electric services to avoid wildfires during windy periods in California, a business disruption risk that is not insured. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and natural gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have a material adverse impact on us because of legal costs, diversion of the attention of management and other personnel and other factors. In addition, resolution of one or more such proceedings could result in liability, loss of contractual or other rights, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change materially from one period to the next.

The loss of senior management or technical personnel could adversely affect our results and operations.

We depend on, and could be deprived of, the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of services of any of these individuals.

Information technology and operational failures and cyberattacks could significantly affect our business, financial condition, results of operations and cash flows.

We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. User access and security of our sites and systems are critical elements of our operations, as are cloud security and protection against cybersecurity incidents. Without accurate data from and access to these systems and networks, our ability to communicate, control and manage our business could be adversely affected.

We face various cybersecurity threats, including attempts to gain unauthorized access to sensitive information, or render data, or systems unusable. We also face threats to the security of our facilities, third-party facilities and operational technology and infrastructure such as processing plants and pipelines. We are also susceptible to threats from malicious threats and advanced nation state threat actors. We have experienced cybersecurity incidents but have not suffered any material adverse impacts to our business and operations as a result of such incidents. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches or other incidents from occurring. If a security breach were to occur, it could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations, misdirected wire transfers, an inability to settle transactions or maintain operations, disruptions in operations or other adverse events. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant and could harm our reputation and lead to financial losses from remedial actions, loss of business or potential liability, including regulatory enforcement, violation of privacy or securities laws and regulations, and individual or class action claims.

The energy industry has become increasingly dependent on digital technologies to conduct day-to-day operations, and the use of mobile communication devices has rapidly increased. Industrial control systems such as supervisory control and data acquisition ("SCADA") systems now control large-scale processes that can include multiple sites across long distances. The Company's technologies, systems, networks, including its SCADA system, and those of its business partners may become the target of cyber-attacks or security breaches. In addition, the frequency and magnitude of cyber-attacks is increasing and attackers have become more sophisticated. Cyber-attacks are similarly evolving and include without limitation use of malicious software, surveillance, credential stuffing, spear phishing, social engineering, use of deepfakes (i.e., highly realistic synthetic media generated by artificial intelligence), attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. We may be unable to anticipate, detect or prevent future attacks, particularly as the methodologies used by attackers change frequently or are not recognized until deployed. We may also be unable to investigate or remediate incidents as attackers are increasingly using techniques and tools designed to circumvent controls, to avoid detection, and to remove or obfuscate forensic evidence.

Increasing attention to environmental, social and governance (ESG matters may impact our business.

Increasing attention to, and social expectations on companies to address, climate change and other environmental and social impacts, investor and societal explanations regarding voluntary ESG disclosures, and increased consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors. While we may participate in various voluntary frameworks and certification programs to improve the ESG profile of our operations and products, we cannot guarantee that such participation or certification will have the intended results on our or our products' ESG profile.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures will be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Additionally, while we may also announce various voluntary ESG targets in the near future, such targets are aspirational. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent we do meet such targets, it may be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that, notwithstanding our reliance on any reputable third party registries, that the offsets we do purchase will successfully achieve the emissions reductions they represent. Also, despite these aspirational goals, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us or our customers and to the diversion of investment to other industries which could have a negative impact on our stock price and/or our access to and costs of capital. Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations.

Public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," *i.e.* misleading information or false claims overstating potential ESG benefits. For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG statements, goals, or standards were misleading, false or otherwise deceptive. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further ESG-related focus and scrutiny.

Such ESG matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

Risks Related to Our Financial Condition

We may not be able to use a portion of our net operating loss carryforwards and other tax attributes to reduce our future U.S. federal and state income tax obligations, which could adversely affect our cash flows.

We currently have substantial U.S. federal and state net operating loss ("NOL") carryforwards and U.S. federal general business credits. Our ability to use these tax attributes to reduce our future U.S. federal and state income tax obligations depends on many factors, including our future taxable income, which cannot be assured. In addition, our ability to use NOL carryforwards and other tax attributes may be subject to significant limitations under Section 382 and Section 383 of the Internal Revenue Code of 1986, as amended (the "Code"). Under those sections of the Code, if a corporation undergoes an "ownership change" (as defined in Section 382 of the Code), the corporation's ability to use its pre-change NOL carryforwards and other tax attributes may be substantially limited.

Determining the limitations under Section 382 of the Code is technical and highly complex. A corporation generally will experience an ownership change if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. We may in the future undergo an ownership change under Section 382 of the Code. If an ownership change occurs, our ability to use our NOL carryforwards and other tax attributes to reduce our future U.S. federal and state income tax obligations may be materially limited, which could adversely affect our cash flows.

Our business requires continual capital expenditures. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves or production. Our capital program is also susceptible to risks, including regulatory and permitting risks, that could materially affect its implementation.

Our industry is capital intensive. We have a 2024 capital expenditure budget for E&P operations, CJWS and corporate activities between $95 to $110 million. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of permits, and our ability to obtain them in a timely manner or at all, legal and regulatory processes and other restrictions, and technological and competitive developments. Our current capital program for 2024 focuses on new wells drilled during the year for which we already have permits or have existing CEQA analysis completed, and otherwise focuses on workovers and other activities related to existing wellbores. We also expect to benefit from a full year of production from the assets acquired in the Macpherson Acquisition and other bolt-on acquisitions at the end of 2023, which should help keep our production essentially flat in 2024. As a result of ongoing regulatory uncertainty in California, the capital program has been prepared based on the assumption that no permits for new wells will be issued under the Kern County EIR in 2024. In addition, a reduction or sustained decline in commodity prices from current levels may force us to reduce our capital expenditures, which would negatively impact our ability to grow production. Current and future laws and regulations may prevent us from being able to execute our drilling programs and development and optimization projects.

We expect to fund our 2024 capital expenditures with cash flows from our operations; however, our cash flows from operations, and access to capital should such cash flows and cash prove inadequate, are subject to a number of variables, including:

- the volume of hydrocarbons we are able to produce from existing wells and our ability to bring those to market;
- the prices at which our production is sold and our operating expenses;
- the success of our hedging program;
- our proved reserves, including our ability to acquire, locate and produce new reserves;
- our ability to borrow under the 2021 RBL Facility; and

- our ability to access the capital markets.

If our revenues or the borrowing base under the 2021 RBL Facility decrease as a result of lower oil, natural gas and NGL prices, lack of required permits and other operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital were needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. Any additional debt financing would carry interest costs, diverting capital from our business activities, which in turn could lead to a decline in our reserves and production. If cash flows generated by our operations or available borrowings under the 2021 RBL Facility were not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Inflation could adversely impact our ability to control our costs, including our operating expenses and capital costs.

The U.S. inflation rate has become more significant in recent years. Similar to other companies in our industry, we experienced inflationary pressures on our operating 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 pandemic, increased demand, labor shortages and other factors, including the conflict between Russia and the Ukraine. During 2023, inflation rates began to stabilize and even decrease. We are unable to accurately predict if such inflationary pressures and contributing factors will continue through 2024. To the extent inflation begins to increase again, we may experience further cost increases for our operations, including natural gas purchases and oilfield services and equipment as increasing oil, natural gas and NGL prices increase drilling activity in our areas of operations, as well as increased labor costs. An increase in oil, natural gas and NGL prices may cause the costs of materials and services to rise. We cannot predict any future trends in the rate of inflation and a significant increase in inflation, to the extent we are unable to recover higher costs through higher commodity prices and revenues, would negatively impact our business, financial condition and results of operations.

Our hedging activities limit our ability to realize the full benefits of increases in commodity prices and our potential gains.

We enter into hedges to manage our exposure to price risks in the marketing of our oil and natural gas, mitigate our economic exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. 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 proved developed producing ("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 (each, a "Minimum Hedging Requirement Date") 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.

While intended to reduce the effects of volatile oil and natural gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge or expose us to the risk of financial losses depending on commodity price movements and other circumstances. Our ability to realize the benefits of our hedges also depends in part upon the counterparties to these contracts honoring their financial obligations. If any of our counterparties are unable to perform their obligations in the future, we could be exposed to increased cash flow volatility that could affect our liquidity.

We may be unable to, or may choose not to, enter into sufficient fixed-price purchase or other hedging agreements to fully protect against decreasing spreads between the price of natural gas and oil on an energy equivalent basis or may otherwise be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels, and our commodity price risk management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

To develop our heavy oil in California we must economically generate steam using natural gas. Particularly in California, natural gas prices can be extremely volatile, as for example, prices experienced a significant increase in mid-December 2022, with gas prices briefly as high as $50.79 per mmbtu. We seek to reduce our exposure to the potential unavailability of, pricing increases for, and volatility in pricing of, natural gas by entering into fixed-price purchase agreements and other hedging transactions. We seek to reduce our exposure to potential price increases and volatility in pricing of oil by entering into swaps, calls and other hedging transactions. We may be unable to, or may choose not to, enter into sufficient agreements to fully protect against decreasing spreads between the price of natural gas and oil on an energy equivalent basis or may otherwise be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels.

In addition, we also hedge our oil production to meet the hedging requirements of the 2021 RBL Facility as described in the risk factor above.

Our commodity price risk management activities as well as the hedging requirements of the 2021 RBL facility may prevent us from fully benefiting from price increases. Additionally, our hedges are based on major oil and gas indexes, which may not fully reflect the prices we realize locally. Consequently, the price protection we receive may not fully offset local price declines.

As of December 31, 2023, we have hedged gas purchases at the following approximate volumes and prices: 40,100 mmbtu/d at $3.97 per mmbtu in 2024.

Our commodity price risk management activities may also expose us to the risk of financial loss in certain circumstances, including instances in which:

- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements; and
- an event materially impacts oil and natural gas prices in the opposite direction of our derivative positions.

Our existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities. In addition, the borrowing base under the 2021 RBL Facility is subject to periodic redeterminations and our lenders could reduce capital available to us for investment.

The 2021 RBL Facility and the indenture governing our 2026 Notes have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in activities that may be in our long-term best interests. Failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. These agreements contain covenants, that, among other things, limit our ability to:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;

- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- transfer, sell or dispose of assets;
- make investments;
- create certain liens securing indebtedness;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- hedge future production or interest rates;
- repay or prepay certain indebtedness prior to the due date;
- engage in transactions with affiliates; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, the 2021 RBL Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios, which may limit our ability to borrow funds to withstand a future downturn in our business, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of these limitations.

In addition, the 2021 RBL Facility has hedging requirements which may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge or expose us to the risk of financial loss in certain circumstances.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

In addition, the 2022 ABL Facility has restrictive covenants that apply to CJWS that could limit its growth, financial flexibility and our ability to engage in activities that may be in CJWS's long-term best interests, and the 2022 ABL Facility requires C&J Management and C&J to maintain certain financial ratios or to reduce their indebtedness if they are unable to comply with such ratios, which may limit their ability to borrow funds to withstand a future downturn in their business, or to otherwise conduct necessary corporate activities. CJWS may also be prevented from taking advantage of business opportunities that arise because of these limitations. Failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of the 2022 ABL Facility.

The amount available to be borrowed under the 2021 RBL Facility is subject to a borrowing base and will be redetermined semiannually and will depend on the estimated volumes and cash flows of our proved oil and natural gas reserves and other information deemed relevant by the administrative agent of, or two-thirds of the lenders under, the 2021 RBL Facility. We, the administrative agent and lenders, each may request one additional redetermination between each regularly scheduled redetermination. Furthermore, our borrowing base is subject to automatic reductions due to certain asset sales and hedge terminations, the incurrence of certain other debt and other events as provided in the 2021 RBL Facility. For example, the 2021 RBL Facility currently provides that to the extent we incur certain unsecured indebtedness, our borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt that exceeds the amount, if any, of certain other debt that is being refinanced by such unsecured debt. Reduction of our borrowing base under the 2021 RBL Facility could reduce the capital available to us for investment in our business. Additionally, we could be required to repay a portion of the 2021 RBL Facility to the extent that after a redetermination our outstanding borrowings at such time exceed the redetermined borrowing base. The 2022 ABL Facility is also subject to adjustments to the borrowing base.

For additional details regarding the terms of the 2021 RBL Facility, the 2022 ABL Facility and our 2026 Notes, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

As of December 31, 2023, we had $400 million outstanding on our 2026 Notes and $31 million outstanding borrowings under our 2021 RBL Facility, with approximately $159 million of available borrowing capacity. As of December 31, 2023, CJWS had no borrowings outstanding with $7 million of available borrowing capacity under the 2022 ABL Facility. Our ability to make scheduled payments on or to refinance our debt obligations, including the 2021 RBL Facility, the 2022 ABL Facility and our 2026 Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors that may be beyond our control. If oil and natural gas prices remain at low levels for an extended period of time or further deteriorate, our cash flows from operating activities may be insufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. The 2021 RBL Facility, the 2022 ABL Facility and our 2026 Notes currently restrict our ability to dispose of assets and our use of the proceeds from any such disposition. We may not be able to consummate dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due.

Declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in write-downs of the carrying amounts of our assets.

We evaluate the impairment of our oil and natural gas properties whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings.

We have significant concentrations of credit risk with our customers and the inability of one or more of our customers to meet their obligations or the loss of any one of our major oil and natural gas purchasers may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For the year ended December 31, 2023, sales to PBF Holding, Chevron and Phillips 66 accounted for approximately 41%, 20% and 10%, respectively, of our sales. This concentration may impact our overall credit risk because our customers may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us. Also, if we were to lose any one of our major customers, the loss could cause us to cease or delay both production and sale of our oil and natural gas in the area supplying that customer.

Due to the terms of supply agreements with our customers, we may not know that a customer is unable to make payment to us until almost two months after production has been delivered. We do not require our customers to post collateral to protect our ability to be paid.

Risks Related to Regulatory Matters

Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change the requirements governing our operations, including the permitting approval process for oil and gas exploration, extraction, operations and production activities; well stimulation and other enhanced production techniques; and fluid injection or disposal activities, any of which could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy and plans.

Like other companies in the oil and gas industry, our operations are subject to a wide range of complex and stringent federal, state and local laws and regulations. Federal, state and local agencies may assert overlapping authority to regulate in these areas. See "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters" for a description of laws and regulations that affect our business. 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. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, fluid injection and disposal, stimulation, operation, maintenance, transportation, marketing, site remediation, decommissioning, abandonment and water recycling and reuse. These permits are generally subject to protest, appeal or litigation, which could in certain cases delay or halt projects, production of wells and other operations. Additionally, the regulatory burden on the industry increases our costs and consequently may have an adverse effect upon capital expenditures, earnings or competitive position. Failure to comply may result in the assessment of administrative, civil and criminal fines and penalties and liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or limiting our operations.

California, where most of our assets are located, is one of the most heavily regulated states in the United States with respect to oil and gas operations and our operations are subject to numerous and stringent state, local and other laws and regulations that could delay or otherwise adversely impact our operations. The jurisdiction, duties and enforcement authority of various state agencies have significantly increased with respect to oil and natural gas activities in recent years, and these state agencies as well as certain cities and counties have significantly revised their regulations, regulatory interpretations and data collection and reporting requirements and have indicated plans to issue additional regulations of certain oil and natural gas activities in 2024. Moreover, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties. Violations and liabilities with respect to these laws and regulations could result in 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 prospects.

In California, we are also increasingly impacted by policies designed to curtail the production and use of fossil fuels. For example, in September 2020, the Governor of California issued an executive order that seeks to reduce both the supply of and demand for fossil fuels in the state. The executive order established several goals and directed several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of vehicles with internal combustion engines; developing strategies for the closure and repurposing of oil and gas facilities in California; and calling on the California State Legislature to enact new laws prohibiting hydraulic fracturing in the state by 2024 (which CalGEM formally proposed in February 2024). The executive order also directed CalGEM to finish its review of public health and safety concerns from the impacts of oil extraction activities and propose significantly strengthened regulations. At this time, we cannot predict how implementation of these actions and proposals may impact our operations. For additional information, see "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters" and "—Risks Related to Our Operations and Industry—There are significant uncertainties with respect to obtaining permits for oil and gas activities in Kern County, where all of our California operations are located, which could adversely and materially impact our financial condition and results of operations" and "—Risks Related to Our Operations and Industry—Attempts by the California state government to restrict the production of oil and gas could negatively impact our operations and result in decreased demand for fossil fuels within the states where we operate."

Our operations may also be adversely affected by seasonal or permanent restrictions on drilling activities imposed under the Endangered Species Act or similar state laws designed to protect various wildlife, such as the Greater Sage Grouse. Such restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. Permanent restrictions imposed to protect threatened or endangered species or their habitat could prohibit drilling in certain areas or require the implementation of expensive mitigation measures.

Our customers, including refineries and utilities, and the businesses that transport our products to customers are also highly regulated. For example, federal and state agencies have subjected or, proposed subjecting, more gas and liquid gathering lines, pipelines and storage facilities to regulations that have increased business costs and otherwise affect the demand, volatility and other aspects of the price we pay for fuel gas. Certain municipalities have enacted restrictions on the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market for our utility customers and the demand and prices we receive for the natural gas we produce.

Costs of compliance may increase, and operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations, each of which has occurred in the past. For example, our costs have recently begun to increase due to new fluid injection regulations, data requirements for permitting, and idle well decommissioning regulations. In addition, we may experience delays, as we have in the past, due to insufficient internal processes and personnel resource constraints at regulatory agencies that impede their ability to process permits in a timely manner that aligns with our production projects.

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and natural gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. Government authorities have also adopted, proposed, or are otherwise considering new or more stringent requirements for permitting, well construction and public disclosure or environmental review of, or restrictions on, oil and natural gas operations. For example, there has been increased scrutiny with respect to hydraulic fracturing over the years by various state and federal agencies, which scrutiny has extended to oil and gas E&P activities more generally. This has resulted in more stringent regulation with respect to air emissions from oil and gas operations, restrictions on water discharges and calls to remove exemptions for certain oil and gas wastes from federal hazardous waste laws and regulations, amongst other restrictions. Separately, as another example, the scope of the federal Clean Water Act (the "CWA") has been subject to substantial uncertainty in recent years, which has the potential to increase permitting burdens. The U.S. Environmental Protection Agency ("EPA") and the U.S. Army Corps of Engineers ("Corps") under the Obama, Trump and Biden Administrations have pursued multiple rulemakings since 2015 in an attempt to determine the scope of the term "Waters of the United States" ("WOTUS"), and, in several instances, federal courts have vacated these rulemakings. In December 2022, the EPA and Corps released a final revised definition of WOTUS founded upon a pre-2015 definition and including updates to incorporate existing Supreme Court decisions and agency guidance. The new rule was officially published on January 18, 2023, to be effective on March 20, 2023. However, the new rule was challenged and is currently enjoined in 27 states. Moreover, in May 2023, the Supreme Court released its opinion in *Sackett v. EPA*, which involved issues relating to the legal tests used to determine whether wetlands are WOTUS. The *Sackett* decision invalidated certain parts of the January 2023 rule and significantly narrowed its scope, resulting in a revised rule being issued in September 2023. However, due to the injunction of the January 2023 rule, the implementation of the September 2023 rule currently varies by state. In the 27 states subject to the injunction, the agencies are interpreting the definition of WOTUS consistent with the pre-2015 regulatory regime and the changes made by the *Sackett* decision, which utilizes the "continuous surface connection" test to determine if wetlands qualify as WOTUS. In the remaining 23 states, the agencies are implementing the September 2023 rule, which did not define the term “continuous surface connection.” Therefore, some uncertainty remains as to how broadly the September 2023 rule and the *Sackett* decision will be interpreted by the agencies. To the extent implementation of the final rule, results of the litigation, or any action further expands the scope of the CWA’s jurisdiction in areas where we operate, we could face increased costs and delays with respect to obtaining dredge and fill activity permits in wetland areas, which could materially impact our operations in the San Joaquin basin and other areas. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, and preclude us from drilling, completing or stimulating wells, which could have an adverse effect on our expected production, other operations and financial condition.

Changes to elected or appointed officials or their priorities and policies could result in different approaches to the regulation of the oil and natural gas industry. We cannot predict the actions the Governor of California or the California legislature may take with respect to the regulation of our business, the oil and natural gas industry or the state’s economic, fiscal or environmental policies, nor can we predict what actions may be taken in states or at the federal level with respect to environmental laws and policies, including those that may directly or indirectly impact our operations.

Potential future legislation may generally affect the taxation of natural gas and oil exploration and development companies and may adversely affect our operations and cash flows.

In past years, federal and state level legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to natural gas and oil exploration and development companies. Such proposed legislation has included, but has not been limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) repealing the percentage depletion allowance for oil and natural gas properties, (iii) extending the amortization period for certain geological and geophysical expenditures, (iv) eliminating certain other tax deductions and relief previously available to oil and natural gas companies, and (v) increasing the U.S. federal income tax rate applicable to corporations (such as us). It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws could adversely affect our operations and cash flows.

Additionally, in California, there have been proposals for new taxes on profits that might have a negative impact on us. Although the proposals have not become law, campaigns by various special interest groups could lead to future additional oil and natural gas severance or other taxes. The imposition of such taxes could significantly reduce our profit margins and cash flow and otherwise significantly increase our costs.

Derivatives legislation and regulations could have an adverse effect on our ability to use derivative instruments to reduce the risks associated with our business.

The Dodd-Frank Act, enacted in 2010, establishes federal oversight and regulation of the over-the-counter (“OTC”) derivatives market and entities, like us, that participate in that market. Rules and regulations applicable to OTC derivatives transactions, and these rules may affect both the size of positions that we may hold and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, such changes could materially reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to, or otherwise be affected by, such regulations. Even though certain of the European Union implementing regulations have become effective, the ultimate effect on our business of the European Union implementing regulations (including future implementing rules and regulations) remains uncertain.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas E&P activities, and reduce demand for the oil and natural gas we produce.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our oil and natural gas E&P operations are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, with the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the Clean Air Act (the "CAA"), the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the U.S. Department of Transportation ("DOT"), implement GHG emissions limits on vehicles manufactured for operation in the United States. The regulation of methane from oil and gas facilities has been subject to uncertainty in recent years but, in December 2023, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Under the final rules, states have two years to prepare and submit their plans to impose methane emissions controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a "super emitter" response program that would allow third parties to make reports to EPA of larger methane emission events, triggering certain investigation and repair requirements. It is likely, however, that the final rule and its requirements will be subject to legal challenges. Moreover, compliance with the new rules may effect the amount we owe under the Inflation Reduction Act ("IRA"), signed into law on August 16, 2022, which imposes a fee on the emissions of methane from certain sources in the oil and natural gas sector. However, compliance with the EPA's methane rule would exempt an otherwise covered facility from the requirement to pay the fee. For additional information, please see "—The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations." The requirements of the EPA's final methane rules and, as applicable, the IRA's methane emissions fee, could increase our operating costs and accelerate the transition away from oil and gas, which could adversely affect our business and results of operations. Moreover, failure to comply with these requirements could result in the imposition of substantial fines and penalties, as well as costly injunctive relief.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of GHG emissions, such as methane. For example, California, through the California Air Resources Board ("CARB") has implemented a cap and trade program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030. Covered entities must either reduce their GHG emissions or purchase allowances to account for such emissions. Separately, California has implemented Low Carbon Fuel Standard (the "LCFS") and associated tradable credits that require a progressively lower carbon intensity of the state's fuel supply than baseline gasoline and diesel fuels. Recently, CARB proposed amendments to the LCFS program to include increasing 2030 carbon intensity targets from 20% to 30% and extending carbon intensity reduction targets to 90% by 2045. CARB has also promulgated regulations regarding monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production facilities.

In addition to the various actions described requiring California to achieve total economy-wide carbon neutrality by 2045 California has separately adopted a law requiring the use of 100% zero-carbon electricity within the state by 2045. Additionally, the Governor of California requested that the CARB analyze pathways to phase out oil extraction across the state by no later than 2045; however, CARB's 2022 Final Scoping Plan (the "2022 Final Scoping Plan"), the blueprint for the state's carbon neutrality goals, determined such a phase out was not feasible because of continued projected demand for fossil fuels in the transportation sector notwithstanding significant projected decreases in demand for fossil fuels for such uses by 2045. Notwithstanding this, CARB will continue to assess opportunities for phase down in its next five year scoping plan. The 2022 Final Scoping Plan also outlines a plan to phase out natural gas use in buildings, amongst other carbon emission reduction matters. We cannot predict how these various laws, regulations and orders may ultimately affect our operations. However, these initiatives could result in decreased demand for the oil, natural gas and NGLs that we produce, or otherwise restrict or prohibit our operations altogether in California, and therefore adversely affect our revenues and results of operations.

At the international level, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. Although the United States had withdrawn from the Paris Agreement, following an executive order signed by President Biden on his first day in office, the United States rejoined the Paris Agreement in February 2021. In April 2021, the United States established a goal of reducing economy-wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at the 26th Conference of the Parties ("COP26") in Glasgow in November 2021, the United States and the European Union jointly announced the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. The following year, the United States also announced in conjunction with the European Union and other partner countries that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. At COP28, hosted by the United Arab Emirates in December 2023, parties signed onto an agreement to transition "away from fossil fuels in energy systems in a just, orderly, and equitable manner" and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set. The full impact of these actions is uncertain at this time and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon our operations.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates for public office. These have included promises to pursue actions to limit emissions and curtail the production of oil and gas, such as through banning new leases for production of minerals on federal properties. On January 20, 2021, President Biden issued an executive order calling for increased regulation of methane emissions from the oil and gas sector. Subsequently, on January 27, 2021, President Biden issued an executive order that calls for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across agencies and economic sectors. The Biden Administration has also called for restrictions on leasing on federal land, including the Department of Interior's publication of a report in November 2021 recommending various changes to the federal leasing program, though any such changes would require Congressional action; for more information, see "Regulatory Matters—Restrictions on Oil and Gas Developments on Federal Lands." Our operations involve the use of hydraulic fracturing activities and we also have operations on federal lands under the jurisdiction of the BLM within the Department of the Interior (the "DOI"). Other actions that could be pursued by President Biden may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as other GHG emissions limitations for oil and gas facilities.

Litigation risks are also increasing, as a number of parties have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but withheld material information from their investors or customers by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, in October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corp. released a finalized set of principles guiding financial institutions with $100 billion or more in assets on the management of physical and transition risks associated with climate change. Although we cannot predict the effects of actions such as this, such limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities. Additionally, in March 2022, the SEC released a proposed rule that would establish a framework for the reporting of climate risks, targets, and metrics. We cannot predict the final form and substance of the rule and its requirements. The ultimate impact of the rule on our business is uncertain and, upon finalization, may result in additional costs to comply with any such disclosure requirements, alongside increased costs of and restrictions on access to capital. Separately, the SEC has also announced that it is scrutinizing existing climate-changed related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer's climate disclosures are misleading, deceptive or deficient. Such agency action could increase the potential for private litigation.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from oil and natural gas producers such as ourselves or otherwise restrict the areas in which we may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or erode value for, the oil and natural gas that we produce. Additionally, political, litigation, and financial risks may result in our restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing our ability to continue to operate in an economic manner. Moreover, climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our operations, as well as those of our operators and their supply chains. Such physical risks may result in damage to our facilities or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact our supply chain or infrastructure on which we rely to produce or transport our products. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the IRA into law. The IRA contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and CCS, amongst other provisions. In addition, the IRA imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The IRA amends the Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year thereafter. Calculation of the fee is based on certain thresholds established in the IRA. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from fossil fuels towards lower- or zero-carbon emission alternatives. Relatedly, on January 12, 2024, the EPA released a proposed rule implementing the requirements of the IRA methane emissions fee; namely, to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from facilities reporting more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases per year pursuant to the petroleum and natural gas system source category requirements of the agency's Greenhouse Gas Reporting Rule. The methane charges and various incentives for clean energy industries could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently materially and adversely affect our business and results of operations.

Risks Related to our Capital Stock

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

A large portion of our common stock is beneficially owned by a relatively small number of stockholders. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures, hostile takeovers or other transactions, including the payment of dividends or the issuance of additional equity or debt, that, in their judgment, could enhance their investment in us or in another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common stock because investors may perceive disadvantages in owning shares in companies with significant stockholder concentrations.

Our significant stockholders and their affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in the Certificate of Incorporation could enable our significant stockholders to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents provide that our stockholders and their affiliates are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, the Certificate of Incorporation, among other things:

- permits stockholders to make investments in competing businesses; and
- provides that if one of our directors who is also an employee, officer or director of a stockholder (a “Dual Role Person”), becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

A Dual Role Person may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which our stockholders have invested, in which case we may not become aware of, or otherwise have the ability to pursue, such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to be unavailable to us or causing them to be more expensive for us to pursue.

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

A large portion of our common stock is beneficially owned by a relatively small number of stockholders. We cannot predict when or whether they will sell their shares of common stock. Future sales, or concerns about them, may put downward pressure on the market price of our common stock.

We may sell or otherwise issue additional shares of common stock or securities convertible into shares of our common stock. Our Certificate of Incorporation provides for authorized capital stock consisting of 750,000,000 shares of common stock and 250,000,000 shares of preferred stock. For more information see Exhibit 4.4 to this Annual Report.

The issuance of any securities for acquisitions, financing, upon conversion or exercise of convertible securities, or otherwise may result in a reduction of the book value and market price of our outstanding common stock. If we issue any such additional securities, the issuance will cause a reduction in the proportionate ownership and voting power of all current stockholders. We cannot predict the size of any future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

On March 1, 2022, the Board of Directors approved the Berry Corporation 2022 (bry) Omnibus Incentive Plan (the "2022 Omnibus Plan"), which was subsequently approved by stockholders on May 25, 2022. Shares of our common stock are reserved for issuance as equity-based awards to employees, directors and certain other persons under the 2022 Omnibus Plan. We have filed a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issued or reserved for issuance under the 2022 Omnibus Plan. Subject to the satisfaction of vesting conditions, the expiration of certain lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 may be made available for resale immediately in the public market without restriction. Investors may experience dilution in the value of their investment upon the exercise of any equity awards that may be granted or issued pursuant to the 2022 Omnibus Plan in the future. The 2022 Omnibus Plan authorized the issuance of 2,950,000 shares of common stock, which amount consists of 2,300,000 shares of common stock newly reserved under the 2022 Omnibus Plan and 650,000 shares of common stock remaining available under the Second Amended and Restated Berry Petroleum Corporation 2017 Omnibus Incentive Plan (the "2017 Omnibus Plan"). The maximum number of shares remaining that may be issued pursuant to the 2022 Omnibus Plan is 2,631,250 as of December 31, 2023.

The payment of dividends will be at the discretion of our Board of Directors.

In 2023, we paid total dividends of $0.97 per share, in the form of regular fixed dividends of $0.42 per share and variable dividends of $0.55 per share. In February 2024, our Board of Directors approved a fixed cash dividend of $0.12 per share, and a variable cash dividend of $0.14 per share based on the results of the fourth quarter of 2023, each of which is expected to be paid in March 2024. There is no certainty that we will generate Adjusted Free Cash Flow, nor is the Board of Directors obligated to make any dividends and any dividends are subject to the restrictions in our debt documents as described below. The payment and amount of future dividend payments, if any, are subject to declaration by our Board of Directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, and other factors our Board of Directors deems relevant. Additionally, covenants contained in our 2021 RBL Facility, 2022 ABL Facility and the indenture governing our 2026 Notes could limit the payment of dividends. We are under no obligation to make dividend payments on our common stock and cannot be certain when such payments may resume in the future.

We may issue preferred stock, the terms of which could adversely affect the voting power or value of our common stock.

Our Certificate of Incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board of Directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our common stock.

Due to our emerging growth company status expiring on December 31, 2023, we have incurred and expect to incur additional costs and demands will be placed upon management in connection with complying with non-emerging growth company requirements. Additionally, our internal control over financial reporting is now required to meet all of the standards required by Section 404 of the Sarbanes-Oxley Act. Failure to achieve and maintain effective internal control over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act could have a material adverse effect on our business and share price.

As an emerging growth company, we benefited from certain temporary exemptions from various reporting requirements. On December 31, 2023, our emerging growth company status expired due to reaching the fifth anniversary of our IPO. This transition from emerging growth company status requires us to, among other things, allow our independent registered public accounting firm to attest to the effectiveness of our internal controls as required by Section 404(b) of the Sarbanes-Oxley Act in this Annual Report.

In addition, as an emerging growth company we had elected under the JOBS Act to delay adoption of new or revised accounting pronouncements applicable to public companies until such pronouncements are made applicable to private companies. As a result of our emerging growth company status expiring as of December 31 2023, we are no longer eligible to delay adoption of such new or revised accounting pronouncements applicable to public companies. In addition to some immaterial expenses, mainly for our independent registered public accounting firm to attest to the effectiveness of our internal controls over financial reporting, our management may need to devote significant time and efforts to implement and comply with the additional standards, rules and regulations that will apply to us losing our emerging growth company status, which may divert such time from the day-to-day conduct of our business operations. Also, due to the complexity and logistical difficulty of implementing the standards, rules and regulations that apply to non-emerging growth companies, such as Section 404(b) of the Sarbanes-Oxley Act, on an accelerated timeframe, the risk of our non-compliance with such standards, rules and regulations or of significant deficiencies or material weaknesses in our internal controls over financial reporting is increased.

Effective internal controls are necessary for us to provide reliable financial reports, safeguard our assets, and prevent fraud. If we cannot provide reliable financial reports, safeguard our assets or prevent fraud, our reputation and operating results could be harmed. The rules governing the standards that must be met for our management to assess our internal control over financial reporting are complex and require significant documentation, testing and possible remediation.

We may encounter problems or delays in completing the implementation of effective internal controls. Further, failure to achieve and maintain an effective internal control environment could have a material adverse effect on our business and share price and could limit our ability to report our financial results accurately and timely.

Certain provisions of our Certificate of Incorporation and Bylaws may make it difficult for stockholders to change the composition of our Board of Directors and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Certificate of Incorporation and Bylaws may have the effect of delaying or preventing changes in control if our Board of Directors determines that such changes in control are not in the best interests of us and our stockholders. For more information see Exhibit 4.4 to this Annual Report.

For example, our Certificate of Incorporation and Bylaws include provisions that (i) authorize our Board to issue "blank check" preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval and (ii) establish advance notice procedures for nominating directors or presenting matters at stockholder meetings.

These provisions could enable the Board of Directors to delay or prevent a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may discourage or prevent attempts to remove and replace incumbent directors. These provisions may also discourage or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board of Directors, which is responsible for appointing the members of our management.

Our Certificate of Incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders, (iii) any action asserting a claim against us, our directors, officers or employees arising pursuant to any provision of the Delaware General Corporation Law, our Certificate of Incorporation or our Bylaws or (iv) any action asserting a claim against us, our directors, officers or employees that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having subject matter jurisdiction and personal jurisdiction over the indispensable parties named as defendants therein. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our Certificate of Incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Description of Processes for Assessing, Identifying, and Managing Cybersecurity Risks

Our business operations depend on the performance and availability of our information systems, which we use to communicate, control and manage our operations and prepare our financial management and reporting information. The efficiency of our business and our operations rely heavily on these systems. We seek to assess, identify, and manage cybersecurity risks through the processes described below:

- *Risk Assessment*:

  A multi-layered system has been implemented to protect and monitor data and cybersecurity risk. Assessments of our cybersecurity safeguards are regularly conducted by both internal security staff and independent third-party cybersecurity vendors. These assessments include, but are not limited to, vulnerability assessments, penetration tests, and internal security control reviews. Our internal Information Technology ("IT") team performs regular evaluations to assess, identify, and manage material cybersecurity risks. We aim to update our cybersecurity infrastructure, procedures, policies, and education programs in response to these evaluations.

- *Incident Identification and Response:*

  Firewalls and an extended detection and response (XDR) platform have been implemented to identify cybersecurity incidents. In the event of a breach or cybersecurity incident, we have an incident response plan and policy in place to guide our incident response team in the identification and mitigation of threats, with the goal of facilitating a return to normal operations. The plan and policy describes processes for internal escalation of cybersecurity incidents deemed to have a moderate or higher business impact, even if immaterial to us, from the head of IT to the Company's senior management and to the Audit Committee and/or Board of Directors, as appropriate.

- *Cybersecurity Training and Awareness*:

  All new hires receive cybersecurity awareness training. All employees and contractors receive annual training and are periodically subject to drills and simulated attacks. Our organization leverages cybersecurity vendors to perform cybersecurity tabletop exercises at regular intervals to test the effectiveness of our incident response plan and to implement post-incident "lessons learned" to improve our response.

- *Access Controls*:

  Users are provided with access consistent with the principle of least privilege, providing them with access that is consistent with their job functions and no more. We have implemented a multi-factor authentication process that is required to access company information. User access is reviewed regularly to ensure that it is updated and appropriate.

- *Encryption and Data Protection*:

  Encryption methods are used to protect sensitive data in transit and at rest.

We incorporate third-party service providers and reviews as part of our cybersecurity program. For example, we have engaged an independent cybersecurity advisor to review, assess, and make recommendations regarding our information security program and information technology strategic plan. We recognize that third-party service providers introduce cybersecurity risks. In an effort to mitigate these risks, before engaging with any third-party cybersecurity service provider, we conduct due diligence to evaluate their cybersecurity capabilities. Additionally, we endeavor to include cybersecurity requirements in our contracts with these providers, including requiring them to adhere to security standards and protocols, including with respect to personally identifiable information.

The above cybersecurity risk management processes are integrated into the Company's overall enterprise risk management program. Cybersecurity risks are understood to be significant business risks, and as such, are considered an important component of our enterprise-wide risk management approach.

Impact of Risks from Cybersecurity Threats

As of the date of this Report, though the Company and our service providers have experienced certain cybersecurity incidents, we are not aware of any previous cybersecurity threats that have materially affected or are reasonably likely to materially affect the Company. However, we acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents remains. Despite the implementation of our cybersecurity processes, our security measures cannot guarantee that a significant cyberattack will not occur. A successful attack on our information technology or operational technology systems could have significant consequences to the business. While we devote resources to our security measures to protect our systems and information, these measures cannot provide absolute security. No security measure is infallible. See "Item 1A. Risk Factors" for additional information about the risks to our business associated with a breach or compromise to our IT systems.

Board of Directors' Oversight and Management's Role

The Board of Directors is responsible for overseeing cybersecurity, information security, and information technology risks, as well as management's actions to identify, assess, mitigate, and remediate those risks. As part of its program of regular risk oversight, the Audit Committee assists the Board of Directors in exercising oversight of the Company's cybersecurity, information security, and information technology risks. On a quarterly basis, the Audit Committee reviews and discusses with the head of IT and executive management the Company's policies, procedures, and practices with respect to cybersecurity, information security and information and operational technology, including related risks.

Recognizing the importance of cybersecurity to the success and resilience of our business, the Board of Directors considers cybersecurity to be an important aspect of corporate governance. To facilitate effective oversight, our cybersecurity team, led by our head of IT, holds discussions on cybersecurity risks, incident trends and the effectiveness of cybersecurity measures as necessitated by emerging material cyber risks.

Our cybersecurity team is made up of experienced employees with relevant backgrounds in information security, risk management, and incident response. These backgrounds include relevant degrees, certifications, and relevant work experience, including in roles responsible for cybersecurity oversight in enterprise-level organizations in the energy industry. The experience of the cybersecurity team is also supplemented by the engagement of third-party cybersecurity vendors.

Item 3. 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.

<u>Securities Litigation Matter</u>

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; the settlement funds will be disbursed to the class from an existing escrow account in coming weeks. The Defendants continue to maintain that the claims are without merit and admit no liability in connection with the settlement.

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.

Item 4. Mine Safety Disclosure

Not applicable.

Part II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock has been trading on the Nasdaq Global Select Market under the ticker symbol "bry" since July 26, 2018. Prior to that there was no established public trading market for our common stock.

Holders of Record

Our common stock was held by 27 stockholders of record at February 29, 2024, which does not include the beneficial owners for whom Cede and Co. or others act as nominees.

Dividend Policy

We historically have, and plan to continue using our operating cash flows to fund operations at sustained production levels and routinely return meaningful capital to stockholders in the form of quarterly dividends through commodity price cycles.

We first began paying a quarterly dividend in our first quarter as a public company in 2018, which we paid regularly through the first quarter of 2020. We temporarily discontinued our quarterly dividends in the second quarter of 2020 following the historic oil price drop and economic impact of COVID-19. We reinstated a quarterly dividend at a reduced rate beginning with the first quarter of 2021 and then increased the rate 50% to $0.06 per share beginning with the third quarter of 2021, which continued through the end of 2022. In early February 2023, we updated our shareholder return model and doubled our quarterly fixed dividend to $0.12 per share. In February 2024, our Board of Directors approved a fixed cash dividend of $0.12 per share, and a variable cash dividend of $0.14 per share based on the results of the fourth quarter of 2023. The dividends are payable on March 25, 2024 to shareholders of record at the close of business on March 15, 2024. The payment and amount of future dividend payments, if any, are subject to declaration by our Board of Directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our bank credit agreements and other factors our Board of Directors deems relevant. See "Item 1A. Risk Factors— Risks Related to our Capital Stock—The payment of dividends will be at the discretion of our board of directors."

Sales of Unregistered Securities

None.

Stock Repurchase Program

For the year ended December 31, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million. Since the program began in December 2018 through December 31, 2023, 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 December 31, 2023. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company may allocate a portion of Adjusted Free Cash Flow to opportunistic share repurchases.

In February 2023, the Board of Directors approved an increase of $102 million to the Company's share repurchase authorization. As of December 31, 2023, the Company's remaining share authority 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, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors'. The Board's authorization has no expiration date.

The shares repurchased under the Company's stock repurchase program after December 31, 2022 are subject to a 1% U.S. federal excise tax. The amount subject to the excise tax generally is the fair market value of stock repurchased by the Company during the applicable taxable year net of the fair market value of any stock issued by the Company during such taxable year. The excise tax applies to any stock repurchase program beginning in 2023 and will apply in subsequent taxable years.

The Company's manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements, cash requirements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

Item 6. Reserved

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes included elsewhere in this report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are described in "Item 1A. Risk Factors" included earlier in this report. Please see "*—Cautionary Note Regarding Forward-Looking Statements.*"

This section of the Form 10-K generally discusses 2023 and 2022 items and year-to-year comparisons between those years. For discussion of our year ended December 31, 2021, as well as the year ended 2022 compared to year ended 2021, refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2022 Annual Report on Form 10-K.

Executive Overview

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.

In September 2023, we completed the acquisition of Macpherson Energy (the "Macpherson Acquisition"), a privately held Kern County, California operator. The Macpherson Energy assets are high-quality, low decline oil producing properties that are closely located to existing Berry properties in rural Kern County, California. In December 2023, we acquired additional, highly synergistic working interests in Kern County, California. These assets align with our strategy of acquiring accretive, producing bolt-ons in support of our goal to maintain flat production year-over-year.

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 shareholder value through overall returns. Since our initial public offering in July 2018 ("IPO"), we have demonstrated our commitment to maximizing shareholder value and returning a substantial amount of 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 went into effect January 1, 2022, and we most recently updated the allocations at the beginning of 2023. Specifically, in 2023, the annual cumulative allocation of Adjusted Free Cash Flow was initially set at (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. Our Adjusted Free Cash Flow in 2023 was $97 million, of which $19 million, or approximately 20%, was used to pay variable cash dividends, $10 million was used for share repurchases, $51 million was used for bolt-on acquisitions, most notably the Macpherson Acquisition, and the remaining $17 million was used for other acquisitions and non-E&P capital. In 2023, after giving effect to the dividends declared for the fourth quarter of 2023 in March 2024, we will have returned directly to shareholders a total of $65 million which consisted of: (i) $19 million for the variable cash dividends, (ii) $36 million for fixed cash dividends and (iii) $10 million for share repurchases.

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. 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, 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 have updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and capital expenditures. For 2022 and 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 shareholder 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 "Regulatory Matters

—Regulation of the Oil and Gas Industry." Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safer, more efficient and lower emission operations.

As part of our commitment to creating long-term value for our shareholders, we are dedicated to conducting our operations in an ethical, safe and responsible manner, protecting the environment, and taking care of our people and the communities in which we live and operate. We believe that oil and gas will remain an important part of the energy landscape going forward and our goal is to conduct our business safely and responsibly, while supporting economic stability and social equity through engagement with our stakeholders. We recognize the oil and gas industry's role in the energy transition and advocate a co-existence between renewable and conventional energy. We are committed to being part of the energy transition solution by continuing to provide safe, reliable, and affordable energy to our communities.

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 “Part I— Item 1 “Regulatory Matters” and Part I— Item 1A. “Risk Factors” in this 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. Average oil prices and natural gas prices decreased in 2023 compared to 2022, and experienced further decline late in the fourth quarter of 2023. 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 services and abandonment business is dependent on expenditures of oil and gas companies, which can in part reflect the volatility of commodity prices. 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.

Currently, global oil inventories supplied from OPEC+ and other oil producing nations are expected to transition to inventory decreases throughout the majority of 2024 from inventory builds during the first half of 2023. In October 2022, OPEC+ announced initial reductions in production that extended through December 2023. In June 2023, OPEC+ further reduced production beginning in 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 mbbls/d, beginning January 2024 through March 2024.

Furthermore, sanctions and import bans on Russian oil have been implemented by various countries in response to the ongoing conflict in Ukraine, further impacting 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 recent Israel-Hamas conflict, international sanctions, speculation as to future actions by OPEC+, higher gas prices, rising 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 "Items 1 and 2. Business and Properties-Regulation of Health, Safety and Environmental Matters" for a description of laws and regulations that affect our business. For more information related to regulatory risks, see "Item 1A. Risk Factors**—Risks Related to Our Operations and Industry**".

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 this 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.

	Year Ended December 31,			
	2023		2022	
	Average Price	Realization(1)	Average Price	Realization(1)
Sales of Crude Oil (per bbl):				
Brent	$ 82.18		$ 99.04	
Realized price without derivative settlements	$ 75.05	91%	$ 91.98	93%
Effects of derivative settlements	(3.38)		(14.39)	
Realized price with derivative settlements	$ 71.67	87%	$ 77.59	78%
WTI	$ 77.61		$ 94.39	
Realized price without derivative settlements	$ 75.05	97%	$ 91.98	97%
Purchased Natural Gas (per mmbtu)				
Average Monthly Settled Price - NWPL	$ 8.28		$ 6.95	
Realized price without derivative settlements	$ 8.21	99%	$ 7.86	113%
Effects of derivative settlements	(1.79)		(1.74)	
Realized price with derivative settlements	$ 6.42	78%	$ 6.12	88%

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

Oil Prices

Average Brent oil prices, as noted above, decreased by $16.86 or 17% for the year ended December 31, 2023 compared to the year ended December 31, 2022. In 2023, California had an average realized oil price of $76.89, compared to an average Brent oil price of $82.18. In 2022, California had an average realized oil price of $93.40, compared to an average Brent oil price of $99.04. Though the California market generally receives Brent-influenced pricing, California oil prices are determined by local supply and demand dynamics, including third-party transportation and infrastructure capacity. In 2023, average Brent oil prices decreased from the higher prices observed in 2022, which were primarily related to the significant increase in oil and gas prices during the second quarter of 2022 caused by the Ukraine conflict. In the second half of 2023, prices increased in the third quarter due to stronger than anticipated economic growth and sustained production cuts from Saudi Arabia and Russia, followed by price decreases in the fourth quarter due to a decrease in demand as the overall economy declined.

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.

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. In 2023, Utah had an average realized oil price of $65.38, compared to an average Brent oil price of $82.18. In 2022, Utah had an average realized oil price of $81.09, respectively, compared to an average Brent oil price of $99.04.

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 $49.57 per mmbtu and as low as $2.32 per mmbtu in 2023. The price from the SoCal Gas city-gate index was as high as $54.31 per mmbtu and as low as $4.09 per mmbtu in 2023. Overall, on an unhedged basis, we paid an average of $8.21 per mmbtu in 2023 for our gas purchases. The price we paid on average increased by $0.35 per mmbtu, or 4%, for the year ended December 31, 2023, compared to the year ended December 31, 2022. When including hedging effects in our gas purchases, we paid $6.42 and $6.12 per mmbtu in 2023 and 2022, 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 2023, Utah had an average realized gas price of $6.94, compared to an average Northwest, Rocky Mountains gas price of $8.28, which was a 84% realization. In 2022, Utah had an average realized gas price of $8.13, compared to an average Northwest, Rocky Mountains gas price of $6.95, which was a 117% realization.

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. In May 2022, we began purchasing most of our gas in the Rockies and transporting 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 2023, and 12,000 mmbtu/d in 2022. 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.

Cold weather conditions drove high natural gas prices in 2023. In California, we experienced a significant increase in the first quarter of 2023, with gas prices briefly as high as $54.31 per mmbtu (SoCal Gas city-gate). We pivoted and reduced our gas consumption in California by temporarily shutting down one of our cogeneration facilities and reducing steam generation in other parts of our operation, which negatively impacted production. 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. Natural gas prices in the western US relative to Henry Hub experienced a decline in 2023 compared to 2022. Late in the fourth quarter of 2023, prices experienced further decline compared to the beginning of the quarter. This trend has continued into early 2024. Our current expectations are that the natural gas prices will continue to decrease in early 2024 due to an increase in natural gas production and increased natural gas storage inventory levels. 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.

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.

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 2023, inflation rates began to stabilize and even decrease. We are unable to accurately predict if such inflationary pressures and contributing factors will continue through 2024. However, we determined that there was a decrease in inflationary pressures in the year ended December 31, 2023 compared to the year ended December 31, 2022.

Certain Operating and Financial Information

The following tables set forth information regarding average daily production, total production, and average prices for the years ended December 31, 2023 and 2022. Beginning in the first quarter of 2023, we began purchasing a majority of our fuel gas in the Rockies and the remaining purchases are made in California utilizing the SoCal Gas city-gate index. Prior to this shift, the predominant index for California gas purchases utilized the Kern, Delivered index.

	Year Ended December 31,			
	2023		2022	
Average daily production:[(1)]				
Oil (mbbl/d)		23.5		24.0
Natural Gas (mmcf/d)		8.8		10.2
NGLs (mbbl/d)		0.4		0.4
Total (mboe/d)[(2)]		25.4		26.1
Total Production:				
Oil (mbbl)		8,568		8,770
Natural gas (mmcf)		3,211		3,706
NGLs (mbbl)		155		144
Total (mboe)[(2)]		9,258		9,532
Weighted-average realized sales prices:				
Oil without hedges ($/bbl)	$	75.05	$	91.98
Effects of scheduled derivative settlements ($/bbl)	$	(3.38)	$	(14.39)
Oil with hedges ($/bbl)	$	71.67	$	77.59
Natural gas ($/mcf)	$	6.94	$	7.96
NGLs ($/bbl)	$	24.47	$	43.85
Average Benchmark prices:				
Oil (bbl) – Brent	$	82.18	$	99.04
Oil (bbl) – WTI	$	77.61	$	94.39
Natural gas (mmbtu) – SoCal Gas city-gate[(3)]	$	10.96	$	8.38
Natural gas (mmbtu) – Northwest, Rocky Mountains[(4)]	$	8.28	$	6.95
Natural gas (mmbtu) – Henry Hub[(4)]	$	2.53	$	6.45

(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 year ended December 31, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu respectively.

(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 were 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:

	Year Ended December 31,	
	2023	2022
Average daily production (mboe/d)[1]:		
California	20.7	21.3
Utah	4.7	4.7
	25.4	26.0
Colorado[2]	—	0.1
Total average daily production	25.4	26.1

(1) Production represents volumes sold during the period.

(2) In January 2022, we divested all of our natural gas properties in Colorado.

Year-over-year our overall production decreased 0.7 mboe/d, or 3%. California production decreased 0.6 mboe/d, or 3% due to reduced drilling and workover activity, along with natural base decline. Partially offsetting this was production from the Macpherson Acquisition acquired in September 2023, which contributed 0.5 mboe/d on an annualized basis. Utah production remained flat year-over-year. The Colorado asset was divested in early 2022.

In 2023, we drilled five new wells and 28 new sidetracks in California and no new wells in Utah. In 2022, we drilled 55 new wells and 17 new sidetracks in California, and 13 new wells in Utah. In connection with the closing of the Macpherson Acquisition in September 2023, $35 million was reallocated from the 2023 capital expenditures budget to fund a portion of the purchase price. The capital budget was adjusted to reflect the reduced need for drilling activities on the legacy Berry assets due to the addition of producing assets, allowing Berry to meet production targets while reducing drilling, workover and other activities on the legacy Berry assets California and Utah.

Results of Operations

	Year Ended December 31, 2023	2022	$ Change	% Change
		(in thousands)		
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$ 669,110	$ 842,449	$ (173,339)	(21)%
Services revenue[1]	178,554	181,400	(2,846)	(2)%
Electricity sales	15,277	30,833	(15,556)	(50)%
Gains (losses) on oil and gas sales derivatives	40,006	(137,109)	177,115	n/a
Other revenues	513	768	(255)	(33)%
Total revenues and other	$ 903,460	$ 918,341	$ (14,881)	(2)%

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was $186 million and $184 million, and after the intercompany elimination of $7 million and $3 million, net service revenue was $179 million and $181 million for years ended December 31, 2023 and 2022, respectively.

Revenues and Other

We hedge a significant portion of our oil sales in order to protect our anticipated cash flows from oil price decreases, as well as to meet the hedging requirements of the 2021 RBL Facility. In 2023, our realized oil price was $75.05 per bbl and the hedged price was $71.67 per bbl. By comparison, in 2022, our realized oil price was $91.98 per bbl and our hedged price was $77.59 per bbl.

Oil, natural gas and NGL sales decreased by $173 million, or 21%, to approximately $669 million for the year ended December 31, 2023 when compared to the year ended December 31, 2022. The decrease was driven by $148 million of lower prices and $25 million of lower volumes, which included an addition of $14 million attributable to the assets acquired in the Macpherson Acquisition.

Service revenue, as presented, consisted entirely of revenue from the well servicing and abandonment business provided to third parties. Service revenue decreased by $3 million, or 2%, to approximately $179 million for the year ended December 31, 2023 when compared to the year ended December 31, 2022 due to a small shift in services from third parties to our E&P segment.

Electricity sales which represent sales to utilities decreased by $16 million, or 50%, to approximately $15 million for the year ended December 31, 2023 when compared to the year ended December 31, 2022. The decrease was due to lower electricity sales volume as we reduced operation of one of our cogeneration facilities in 2023 to maximize cost efficiencies.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. In the years ended December 31, 2023 and December 31, 2022, settlement losses were $29 million and $126 million, respectively. The period-over-period decrease in settlement losses were driven by a narrower spread between the settled derivative fixed prices and index oil prices in 2023 compared to 2022. The mark-to-market non-cash gain was $69 million for the year ended December 31 2023 compared to a loss of $11 million in 2022. 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).

	Year Ended December 31, 2023	Year Ended December 31, 2022	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 316,726	$ 302,321	$ 14,405	5 %
Costs of services[1]	141,771	142,819	(1,048)	(1)%
Electricity generation expenses	7,079	21,839	(14,760)	(68)%
Transportation expenses	4,486	4,564	(78)	(2)%
Marketing expenses	—	299	(299)	(100)%
Acquisition costs	3,338	—	3,338	100 %
General and administrative expenses	95,873	96,439	(566)	(1)%
Depreciation, depletion and amortization	160,542	156,847	3,695	2 %
Taxes, other than income taxes	57,973	39,495	18,478	47 %
Losses (gains) on natural gas purchase derivatives	26,386	(88,795)	115,181	n/a
Other operating (income) expenses	(1,788)	3,722	(5,510)	(148)%
Total expenses and other	812,386	679,550	132,836	20 %
Other (expenses) income:				
Interest expense	(35,412)	(30,917)	4,495	15 %
Other, net	(237)	(142)	95	67 %
Total other (expenses) income	(35,649)	(31,059)	4,590	15 %
Income before income taxes	55,425	207,732	(152,307)	(73)%
Income tax expense (benefit)	18,025	(42,436)	60,461	142 %
Net income	$ 37,400	$ 250,168	$ (212,768)	(85)%
Adjusted EBITDA[2]	$ 268,257	$ 379,948	$ (111,691)	(29)%
Adjusted Net Income (Loss)[2]	$ 39,230	$ 226,463	$ (187,233)	(83)%

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $149 million and $146 million, and after the intercompany elimination of $7 million and $3 million, net costs of services was $142 million and $143 million for the years ended December 31, 2023 and 2022, respectively.

(2) 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 "Item 7 — Non-GAAP Financial Measures."

Expenses

Lease operating expense increased 5% on an absolute dollar basis, when compared to the prior year. Fuel consumption decreased 12% compared to 2022, which decreased fuel costs 8%, net of a 4% increase in average natural gas prices. Lease operating expense excluding fuel increased 12% on an absolute dollar basis due to higher outside services and lease maintenance costs, mostly weather related in the first quarter of 2023, as well as increased power costs driven by higher rates.

Cost of services decreased $1 million, or 1%, to $142 million for the year ended December 31, 2023 compared to 2022 due to a change in mix and volume of services.

Electricity generation expenses decreased 68% to $0.76 per boe for the year ended December 31, 2023 from $2.29 for the year ended December 31, 2022 due to lower volumes sold resulting from operating one of our cogeneration facilities for a portion of the year compared to running it all of 2022 to maximize the margin efficiency of these facilities. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements discussed elsewhere.

Acquisition costs were $3 million for the year ended December 31, 2023 due to the Macpherson Acquisition in the third quarter of 2023.

Gain or loss on natural gas purchase derivatives for the year ended December 31, 2023 and 2022 was a loss of $26 million and a gain of $89 million, respectively. The settlement gain for the year ended December 31, 2023 was $35 million, or $3.76 per boe, compared to gain of $38 million, or $4.00 per boe for same period in 2022. The decrease in settlement gain is due to a narrower spread between the settled fixed price and the index price in 2023 compared to 2022. Settled hedges in 2023 had an average fixed price of $5.25 and notional quantities of 40,000 mmbtu per day, compared to $4.21 and 38,000 in 2022. The mark-to-market valuation gain or loss for the years ended December 31, 2023 and December 31, 2022 was a loss of $61 million and a gain of $51 million, respectively, consistent with the changes in futures prices at the end of each period.

General and administrative expenses decreased by approximately $1 million or 1%, for the year ended December 31, 2023 compared to the year ended December 31, 2022. For the year ended December 31, 2023 and 2022, non-cash stock compensation costs were approximately $14 million and $16 million, respectively, and non-recurring costs were $9 million and $3 million, respectively. The non-recurring costs in 2023 consisted primarily of executive transition costs, workforce reduction costs and shareholder litigation expenses. The non-recurring costs in 2022 consisted of executive transition costs.

Adjusted general and administrative expenses, which excluded non-cash stock compensation costs and non-recurring costs, decreased $3 million to $73 million compared to $76 million in 2022. The year-over-year decrease was primarily due to cost saving initiatives implemented in early 2023. Additionally, in 2023 adjusted general and administrative expenses included $3 million in shareholder litigation expenses. See "—Non-GAAP Financial Measures" for a reconciliation of general and administrative expense, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General Administrative and Administrative Expenses.

DD&A increased by $4 million, or 2%, to approximately $161 million, for the year ended December 31, 2023 compared to the year ended December 31, 2022 due to an increase in depletion rates.

Taxes, Other Than Income Taxes

	Year Ended December 31,			
	2023	**2022**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 1.53	$ 1.46	$ 0.07	5 %
Ad valorem taxes	2.04	1.68	0.36	21 %
Greenhouse gas allowances	2.70	1.00	1.70	170 %
Total taxes other than income taxes	$ 6.27	$ 4.14	$ 2.13	51 %

Taxes, other than income taxes, increased $2.13 to $6.27 per boe for the year ended December 31, 2023 compared to $4.14 for the year ended December 31, 2022. GHG expense increased due to higher GHG emission prices in a volatile California carbon allowance market, partially offset by lower GHG emissions.

Other Operating (Income) Expense

For the year ended December 31, 2023, other operating income was $2 million and mainly consisted of net property tax refunds from prior periods and a net gain on equipment sales. For the year ended December 31, 2022, other operating expenses were $4 million and mainly consisted of $2 million in charges from a royalty audit related to activity prior to our emergence and restructuring in 2017 and approximately $2 million loss on the divestiture of the Piceance, Colorado properties.

Interest Expense

Interest expense increased by $4 million, or 15%, for the year ended December 31, 2023 compared to the same period in 2022 as a result of higher working capital borrowings for acquisitions on the RBL Facility in 2023.

Income Tax Expense (Benefit

For the year ended December 31, 2023, we had income tax expense of approximately $18 million and a tax benefit of approximately $42 million in 2022. The change in our effective tax rate to 32.5% for the year ended December 31, 2023 from (20.4)% for the year ended December 31, 2022 was primarily due to recognition of U.S. federal general business credits in 2022 related to the 2021 tax period and release of the valuation allowance in 2022. The credits are available to offset future federal income tax liabilities. The credits recorded in 2022 are available to offset future income tax liabilities. See Note 8, Income Taxes, in the Notes to Consolidated Financial Statements in Part II—Item 8. “Financial Statements and Supplementary Data” for more information about our income taxes.

E&P Field Operations

	Year Ended December 31,			
	2023	2022	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 34.21	$ 31.72	$ 2.49	8 %
Electricity generation expenses	0.76	2.29	(1.53)	(67)%
Transportation expenses	0.48	0.48	—	— %
Marketing expenses	—	0.03	(0.03)	(100)%
Total	$ 35.45	$ 34.52	$ 0.93	3 %
Cash settlements received for gas purchase hedges	$ (3.76)	$ (4.00)	$ 0.24	(6)%
E&P non-production revenues				
Electricity sales	1.65	$ 3.24	$ (1.59)	(49)%
Transportation sales	0.06	0.05	0.01	20 %
Marketing revenues	—	0.03	(0.03)	(100)%
Total	$ 1.71	$ 3.32	$ (1.61)	(48)%

See “Management’s Discussion and Analysis—How We Plan and Evaluate Operations” for details.

Liquidity and Capital Resources

As of December 31, 2023, we had liquidity of $171 million, consisting of $5 million cash, $159 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.

In early February 2023, we updated our shareholder return model, including the plan to double our quarterly fixed dividend to $0.12 per share. We also modified the allocations of Adjusted Free Cash Flow. Our goal is to continue maximizing shareholder value through overall returns. Beginning in 2023, the annual allocation of Adjusted Free Cash Flow is (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. Consistent with our shareholder return model, Berry views the Macpherson Acquisition as a means of maintaining base production in a challenging regulatory environment and an opportunity to grow production. As a result, we reallocated $35 million of our planned 2023 maintenance capital expenditures to partially fund the purchase price paid in 2023 which enhanced Adjusted Free Cash Flow in 2023, and was used for this acquisition. In December 2023, we acquired additional, highly synergistic working interests in Kern County, California, using our 2021 RBL to initially fund the purchase and we expect this balance will be paid off in 2024 with a portion of that year's 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 I— Item 1A. "Risk Factors" for a discussion of known material risks, many of which are beyond our control, that could adversely impact our business, liquidity, financial condition, and results of operations.

2021 RBL Facility

See Note 3, Debt, in the Notes to Consolidated Financial Statements in Part II—Item 8. "Financial Statements and Supplementary Data" of this report for details.

2022 ABL Facility

See Note 3, Debt, in the Notes to Consolidated Financial Statements in Part II—Item 8. "Financial Statements and Supplementary Data" of this report for details. On November 15, 2023, C&J and C&J Management entered into the Second Amendment to Credit Agreement, pursuant to which, among other things, the requisite lender agreed to reduce the maximum borrowing base from $15 million to $10 million. The higher borrowing base amount was not used and the reduction of the borrowing base will reduce costs.

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 December 31, 2023.

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."

As of February 29, 2024, we had the following crude oil production and gas purchases hedges:

	Q1 2024	Q2 2024	Q3 2024	Q4 2024	FY 2025	FY 2026
Brent - Crude Oil Production						
Swaps						
Hedged volume (bbls)	1,536,118	1,611,294	1,481,749	1,438,656	2,669,125	1,881,768
Weighted-average price ($/bbl)	$ 78.95	$ 78.97	$ 76.87	$ 76.94	$ 75.22	$ 70.84
Sold Calls(1)						
Hedged volume (bbls)	122,000	91,000	92,000	92,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 91.11	$ 85.53
Purchased Puts (net)(2)						
Hedged volume (bbls)	318,500	318,500	322,000	322,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 58.53	$ 60.00
Sold Puts (net)(2)						
Hedged volume (bbls)	45,500	45,500	46,000	46,000	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ —	$ —
NWPL - Natural Gas Purchases(3)						
Swaps						
Hedged volume (mmbtu)	3,040,000	3,640,000	3,680,000	3,680,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 4.11	$ 3.96	$ 3.96	$ 3.96	$ 4.27	$ —
HH - Natural Gas Purchases(3)						
Purchased Calls						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 3.38	$ —	$ —	$ —	$ —	$ —
Gas Basis Differentials						
NWPL/HH - Natural Gas Purchases(3)						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 4.10	$ —	$ —	$ —	$ —	$ —

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

(2) Purchased puts and sold puts have been presented on a net basis.

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

Gains (losses) on Derivatives

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

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Realized gains (losses) on commodity derivatives:			
Realized (losses) on oil and gas sales derivatives	$ (28,917)	$ (126,176)	$ (142,531)
Realized gains on natural gas purchase derivatives	34,812	38,153	50,897
Total realized gains (losses) on derivatives	5,895	(88,023)	(91,634)
Unrealized gains (losses) on commodity derivatives:			
Unrealized gains (losses) on oil and gas sales derivatives	68,923	(10,933)	(13,868)
Unrealized (losses) gains on natural gas purchase derivatives	(61,198)	50,642	(12,320)
Total unrealized gains (losses) on derivatives	7,725	39,709	(26,188)
Total gains (losses) on derivatives	$ 13,620	$ (48,314)	$ (117,822)

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

	Year Ended December 31,	
	2023	2022
Sales of Crude Oil (per bbl):		
Realized sales price, before the effects of derivative settlements	$ 75.05	$ 91.98
Effects of derivative settlements	$ (3.38)	$ (14.39)
Realized sales price, after the effects of derivative settlements	$ 71.67	$ 77.59
Purchased Natural Gas (per mmbtu):		
Purchase price, before the effects of derivative settlements	$ 8.21	$ 7.86
Effects of derivative settlements	$ (1.79)	$ (1.74)
Purchase price, after the effects of derivative settlements	$ 6.42	$ 6.12

Cash Dividends

In 2023, we paid total dividends of $0.97 per share, in the form of regular fixed dividends of $0.42 per share and variable dividends of $0.55 per share. These amounts include fixed and variable dividends declared and paid in 2023 related to the fourth quarter 2022 results of $0.06 and $0.44 per share, respectively. In February 2024, our Board of Directors approved a fixed cash dividend of $0.12 per share, and a variable cash dividend of $0.14 per share based on the results of the fourth quarter of 2023, each of which is expected to be paid in March 2024.

The following table represents the regular fixed cash dividends on our common stock and variable cash dividends approved by our Board of Directors based on 2023 results.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year-to-Date
Fixed Dividends	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.48
Variable Dividends(1)	—	0.02	0.09	0.14	0.25
Total	$ 0.12	$ 0.14	$ 0.21	$ 0.26	$ 0.73

(1) Variable Dividends are declared the quarter following the period of results (the period used to determine the variable dividend). The table notes total dividends earned in each quarter. In February 2024, the Board of Directors approved a $0.14 variable dividend based on the results for the three months ended December 31, 2023.

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

For the year ended December 31, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million. Since the program began in December 2018 through December 31, 2023, the Company had repurchased a total of 11.9 million shares, cumulatively under the stock repurchase program for approximately $114 million in aggregate.

In February 2023, the Board of Directors approved an increase of $102 million to the Company's stock repurchase authorization increasing the Company's share authority to $200 million. As of December 31, 2023, the Company's remaining total share repurchase authority 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, 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.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and do 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.

Capital Program

Refer to Part I—Items 1 and 2. — "Our Capital Program" for details.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of December 31, 2023:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
			(in thousands)		
Debt obligations:					
RBL Facility	$ 31,000	$ —	$ 31,000	$ —	$ —
2026 Notes	400,000	—	400,000	—	—
Interest[(1)]	59,500	28,000	31,500	—	—
Deferred acquisition payable[(2)]	18,999	18,999	—	—	—
Other:					
Leases	8,979	3,369	4,002	1,554	54
Asset retirement obligations[(3)]	196,578	20,000	—	—	176,578
Off-Balance Sheet arrangements:[(4)]					
Transportation contracts[(5)]	81,253	11,517	18,133	16,165	35,438
Other purchase obligations[(6)]	17,100	8,400	8,700	—	—
Total contractual obligations	$ 813,409	$ 90,285	$ 493,335	$ 17,719	$ 212,070

(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 Macpherson Acquisition 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 Financials in Part II— Item 8. “Financial Statements and Supplementary Data” 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) Amounts include a drilling commitment in California, for which we are required to drill 57 wells with a minimum commitment of $17.1 million by June 2025. In September 2023, the drilling commitment was amended to defer 28 of these wells to be drilled by December 2024 (previously required to be drilled by October 1, 2023), and the remaining 29 wells to be drilled by June 2025 (previously required to be drilled by June 1, 2024).

Acquisitions and Divestitures

<u>Acquisitions in 2023</u>

In September 2023, we completed the acquisition of Macpherson Energy, a privately held Kern County, California operator. The total purchase price is approximately $70 million, subject to customary purchase price adjustments. The transaction was structured such that approximately $53 million was paid at closing, including purchase price adjustments, and approximately $20 million will be paid in July 2024, subject to purchase price adjustments.

Berry views this acquisition, in part, as a means of maintaining base production in a challenging regulatory environment and an opportunity to grow production. As a result, a total of $35 million was reallocated from the 2023 capital expenditures budget to fund a portion of the purchase price, which enhanced Adjusted Free Cash Flow in 2023, and was used for this acquisition. A portion of the closing price was initially funded by drawing down the 2021 RBL Credit Facility, which was fully repaid in the fourth quarter of 2023.

We acquired Macpherson Energy because their assets are high-quality, low decline oil producing properties that are closely located to existing Berry properties in rural Kern County, California. These assets also align with Berry's stated strategy of acquiring accretive, producing bolt-ons. Macpherson Energy is reported under the E&P business segment.

Also in December 2023, we acquired additional highly synergistic working interests in Kern County, California, for $33 million after purchase price adjustments. This transaction, supports our overall strategic plan to efficiently maintain our California production. During 2023, we also acquired various oil and gas properties which consisted of proved properties, for approximately $10 million in aggregate. Each of these acquisitions was accounted for as an asset acquisition as substantially all of the fair value was concentrated in oil and gas property interests.

<u>Acquisitions and Divestitures in 2022</u>

In January 2022, we completed the divestiture of all of our natural gas properties in Colorado, which were in the Piceance basin. The divestiture closed with a loss of approximately $2 million. Our 2021 production from these properties was 1.2 mboe/d.

In February 2022, we completed the acquisition of oil and gas producing assets in the Antelope Creek area of Utah for approximately $18 million. These assets are adjacent to our existing Uinta assets and prior to our acquisition produced approximately 0.6 mboe/d.

During 2022, we also acquired various oil and gas properties, most of which consisted of unproved properties for approximately $8 million in aggregate.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Net cash:		
Provided by operating activities	$ 198,657	$ 360,941
Used in investing activities	(175,272)	(164,552)
Used in financing activities	(64,800)	(165,422)
Net (decrease) increase in cash and cash equivalents	$ (41,415)	$ 30,967

Operating Activities

Cash provided by operating activities decreased for the year ended December 31, 2023 by approximately $162 million when compared to the year ended December 31, 2022. The decrease was primarily due to lower average realized oil and gas pricing and production volumes, an increase in costs due to the Macpherson Acquisition and higher costs related to winter weather services, partially offset by an increase in the derivative settlements received. Cash provided by operating activities in 2022 was due to higher hedged revenue, which was primarily the result of higher average realized pricing, and lower costs.

Investing Activities

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

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Capital expenditures [(1)]		
Capital expenditures	$ (73,127)	$ (152,921)
Changes in capital expenditures accruals	(7,944)	14,286
Acquisitions, net of cash received	(94,201)	(25,917)
Net cash used in investing activities	$ (175,272)	$ (164,552)

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

Cash used in investing activities increased $11 million for the year ended December 31, 2023 when compared to the year ended December 31, 2022, primarily due to the Macpherson Acquisition. The decreased E&P and corporate capital budget included a reduction in drilling, workover and other activities on the legacy Berry assets, accordingly. Our capital expenditures decreased as a result of reallocating approximately $35 million from the 2023 capital expenditures budget to fund a portion of the purchase price. Cash used in investing activities in 2022 was focused on capital expenditures for increased sidetrack, workover, and recompletion activity in California as a result of challenges in receiving new drill permits, as well as the allocating more capital to Utah assets due in part to opportunities in the newly acquired Antelope Creek properties.

Financing Activities

Cash used in financing activities decreased approximately $101 million for the year ended December 31, 2023 when compared to the year ended December 31, 2022, primarily due to a decrease in the purchase of treasury stock, a decrease in dividends paid, and an increase in our borrowings on our credit facility to pay for a portion of the acquisition in December. Cash used in investing activities in 2022 was used primarily for our fixed and variable dividend payouts and treasury stock repurchases.

Lawsuits, Claims, Commitments and Contingencies

See Note 5, Lawsuits, Claims Commitments and Contingencies, in the Notes to Consolidated Financial Statements in Part II—Item 8. “Financial Statements and Supplementary Data” of this report for details.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2022 to December 31, 2023 are discussed below.

	December 31, 2023		December 31, 2022	
	(in thousands)			
Cash and cash equivalents	$	4,835	$	46,250
Accounts receivable, net	$	86,918	$	101,713
Derivative instruments assets - current and long-term	$	10,751	$	36,443
Other current assets	$	43,759	$	33,725
Property, plant & equipment, net	$	1,406,612	$	1,359,813
Deferred income taxes asset - long-term	$	30,308	$	42,844
Other non-current assets	$	10,975	$	10,242
Accounts payable and accrued expenses	$	213,401	$	203,101
Derivative instruments liabilities - current and long-term	$	10,740	$	44,748
Long-term debt	$	427,993	$	395,735
Deferred income taxes liability - long-term	$	2,344	$	—
Asset retirement obligation - long-term	$	176,578	$	158,491
Other non-current liabilities	$	5,126	$	28,470
Stockholders' equity	$	757,976	$	800,485

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

The $15 million decrease in accounts receivable was primarily attributable to both lower selling prices and volumes in the E&P segment.

The $10 million increase in other current assets was primarily due to an increase of $8 million in purchases of inventory in anticipation of increased development program in 2024, and $6 million in prepaid deposits for insurance and collateral for the electricity contract, partially offset by a decrease of $4 million primarily for the amortization of prepaid expenses.

The $47 million increase in property, plant and equipment was largely due to $105 million in acquisitions, primarily related to the Macpherson Acquisition, $73 million in capital investments and $17 million related to asset retirement obligations, offset by depreciation expense of $148 million.

The $13 million decrease in deferred income taxes asset - long term was primarily due to the tax effect of the book income for the year.

The $10 million increase in accounts payable and accrued expenses included a $38 million increase due to the reclassification of greenhouse gas liabilities from non-current to current as this amount is due in the fourth quarter of 2024, $19 million for the discounted amount due in July 2024 for the Macpherson Acquisition, $2 million in other, partially offset by $39 million of decreased accruals and spending for operating costs for other expenses such as fuel gas purchases and capital expenditures and a $10 million decrease in royalties payable due to decreased sales prices and volumes.

The $8 million increase in net derivatives, which includes both derivative assets and liabilities, is due to the decrease in the the net liability of $8 million in 2022 to a net asset of less than $1 million in 2023. 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 $32 million increase in long-term debt is due to borrowings on our 2021 RBL Facility related to a small acquisition in Kern County in December 2023.

The $2 million increase in long-term deferred income taxes liability was due to the use of IDC deductions.

The $18 million increase in the long-term portion of the asset retirement obligation from $158 million at December 31, 2022 to $177 million at December 31, 2023 was due to $13 million of liabilities for revisions of estimates, $12 million of accretion, and $10 million of liabilities incurred. These increases were partially offset by $17 million of liabilities settled during the period.

The $23 million decrease in other non-current liabilities was the reclassification of greenhouse gas liabilities to current liabilities with the obligation due in the fourth quarter of 2024.

The $43 million decrease in stockholders' equity was due to $78 million of common stock dividends declared, $10 million of treasury stock purchased, and $7 million of shares withheld for payment of taxes on equity awards. These decreases were partially offset by net income of $37 million and $15 million of stock-based compensation.

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 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 Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represents the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and is defined as capital expenditures, excluding, when applicable, (i) E&P capital expenditures that are 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. 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 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.

	Year Ended December 31, 2023	Year Ended December 31, 2022
	(in thousands)	
Adjusted EBITDA reconciliation:		
Net income	$ 37,400	$ 250,168
Add (Subtract):		
Interest expense	35,412	30,917
Income tax expense (benefit)	18,025	(42,436)
Depreciation, depletion and amortization	160,542	156,847
(Gains) losses on derivatives	(13,620)	48,314
Net cash received (paid) for scheduled derivative settlements	5,895	(88,023)
Other operating (income) expenses	(1,788)	3,722
Stock compensation expense	14,356	16,973
Acquisition costs(1)	3,338	—
Non-recurring costs(2)	8,697	3,466
Adjusted EBITDA	$ 268,257	$ 379,948

(1) Consists of costs related to the Macpherson Acquisition.

(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.

	Year Ended December 31, 2023	Year Ended December 31, 2022
	(in thousands)	
Adjusted EBITDA reconciliation:		
Net cash provided by operating activities	$ 198,657	$ 360,941
Add (Subtract):		
Cash interest payments	32,251	29,792
Cash income tax payments	3,282	3,633
Acquisition costs(1)	3,338	—
Non-recurring costs(2)	8,697	3,466
Changes in operating assets and liabilities - working capital(3)	25,654	(21,446)
Other operating (income) expenses - cash portion(4)	(3,622)	3,562
Adjusted EBITDA	$ 268,257	$ 379,948

(1) Consists of costs related to the Macpherson Acquisition.

(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.

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

(4) 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.

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Adjusted Free Cash Flow reconciliation:		
Net cash provided by operating activities[(1)]	$ 198,657	$ 360,941
Subtract:		
Maintenance capital[(2)]	(64,844)	(141,930)
Fixed dividends[(3)]	(36,489)	(19,245)
Adjusted Free Cash Flow	$ 97,324	$ 199,766

(1) On a consolidated basis.

(2) Maintenance capital is the capital required to keep annual production substantially flat, and is calculated as follows:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Consolidated capital expenditures[(a)]	$ (73,127)	$ (152,921)
Excluded items[(b)]	8,283	10,991
Maintenance capital[(c)]	$ (64,844)	$ (141,930)

(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 maintaining flat production in our E&P business. For the years ended December 31, 2023 and 2022, we excluded approximately $6 million and $8 million, respectively, of capital expenditures in our well servicing and abandonment segment, which was substantially all used for sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. In this period, we also excluded approximately $2 million and $3 million, respectively, of corporate capital expenditures, which we determined was not related to the maintenance of our baseline production.

(c) In 2024, we updated the definition of Adjusted Free Cash Flow to 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.

(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.

	Year Ended December 31,			
	2023		2022	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:				
Net income	$ 37,400	$ 0.48	$ 250,168	$ 3.03
Add (Subtract):				
(Gains) losses on derivatives	(13,620)	(0.18)	48,314	0.59
Net cash received (paid) for scheduled derivative settlements	5,895	0.08	(88,023)	(1.07)
Other operating (income) expenses	(1,788)	(0.01)	3,722	0.04
Acquisition costs(1)	3,338	0.04	—	—
Non-recurring costs(2)	8,697	0.11	3,466	0.04
Total additions (subtractions), net	2,522	0.04	(32,521)	(0.40)
Income tax (expense) benefit of adjustments(3)	(692)	(0.01)	8,816	0.11
Adjusted Net Income (Loss)	$ 39,230	$ 0.51	$ 226,463	$ 2.74
Basic EPS on Adjusted Net Income	$ 0.52		$ 2.88	
Diluted EPS on Adjusted Net Income	$ 0.51		$ 2.74	
Weighted average shares of common stock outstanding - basic	76,038		78,517	
Weighted average shares of common stock outstanding - diluted	77,583		82,586	

(1) Consists of costs related to the Macpherson Acquisition.

(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.

(3) The federal and state statutory rates were utilized in both 2023 and 2022.

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.

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Adjusted General and Administrative Expense reconciliation:		
General and administrative expenses	$ 95,873	$ 96,439
Subtract:		
Non-cash stock compensation expense (G&A portion)	(13,681)	(16,498)
Non-recurring costs[1]	(8,697)	(3,466)
Adjusted general and administrative expenses	$ 73,495	$ 76,475
Well servicing and abandonment segment	$ 11,171	$ 12,975
E&P segment, and corporate	$ 62,324	$ 63,500
E&P segment, and corporate ($/boe)	$ 6.73	$ 6.66
Total mboe	9,258	9,532

(1) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with U.S. generally accepted accounting principles ("GAAP") requires management to select appropriate accounting policies and to make informed estimates and judgments regarding certain items and transactions. Changes in facts and circumstances or discovery of new information may result in revised estimates and judgments, and actual results may differ from these estimates upon settlement. We consider the following to be our most critical accounting policies and estimates that involve management's judgment and that could result in a material impact on the financial statements due to the levels of subjectivity and judgment.

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized, grouped by field, and amortized over the remaining life of the associated proved reserves. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in the current period. Gains or losses from the disposal of other properties are recognized in the current period. For assets acquired, we base the capitalized cost on fair value at the acquisition date. We expense expenditures for maintenance and repairs necessary to maintain properties in operating condition, as well as annual lease rentals, as they are incurred. Estimated dismantlement and abandonment costs are capitalized at their estimated net present value and amortized over the remaining lives of the related assets. Interest is capitalized only during the periods in which these assets are brought to their intended use. We only capitalize the interest on borrowed funds related to our share of costs associated with qualifying capital expenditures.

We evaluate the impairment of our proved oil and natural gas properties generally on a field-by-field basis or at the lowest level for which cash flows are identifiable, whenever events or changes in circumstance indicate that the carrying value may not be recoverable. We reduce the carrying values of proved properties to fair value when the expected undiscounted future cash flows are less than net book value. We measure the fair values of proved properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a risk-adjusted discount rate. These inputs require significant judgments and estimates by our management at the time of the valuation. The most significant financial statement effect from a change in our oil and gas reserves or impairment of its proved properties would be to the DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change the DD&A rate by approximately $0.72 per mmboe, which would increase or decrease pre-tax income by approximately $6 million annually at current production rates. In addition, the underlying commodity prices are embedded in our estimated cash flows and are the product of a process that begins with the relevant forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors our management believes will impact realizable prices. The fair value was estimated using inputs characteristic of a Level 3 fair value measurement.

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2023 and 2022, the net capitalized costs attributable to unproved properties was approximately $248 million for both periods. The unproved amounts were not subject to depreciation, depletion and amortization until they were classified as proved properties and amortized on a unit-of-production basis. We evaluate the impairment of our unproved oil and gas properties whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of such properties would be expensed. The timing of any write-downs of unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at December 31, 2023.

Potential Future Impairment

At the end of each quarter, management assesses the carrying value of the proved oil and gas properties for impairment by considering changes in proved reserve quantities, oil and natural gas prices, operating costs, capital costs, and future drilling plans. At December 31, 2023, there was a significant decline in proved reserves quantities in two of our seven depletion units compared to December 31, 2022 due to declining prices and changes in our development plans. Reserves quantities are price sensitive and the year-over-year change in price declined over 17%. In addition, the regulatory environment continues to limit future drilling plans. For all periods presented, we did not record any impairment charges for proved and unproved properties in accordance with the relevant GAAP rules and requirements. However, if we experience further decline in price, reduction in reserve quantities, including due to a change in development plans or regulatory rulings that impact us negatively, the carrying value of these proved oil and gas properties could become partially or entirely impaired.

Acquisition Purchase Price Allocations

We account for acquisitions of businesses using the acquisition method of accounting, which requires the allocation of the purchase price consideration based on the fair values of the assets and liabilities acquired. We estimate the fair values of the assets and liabilities acquired using accepted valuation methods, and, in many cases, such estimates are based on our judgments as to the future operating cash flows expected to be generated from the acquired assets throughout their estimated useful lives. We accounted for the various assets and liabilities acquired and issued as consideration based on our estimates of their fair values. Our estimates and judgments of the fair value of acquired businesses could prove to be inexact, and the use of inaccurate fair value estimates could result in the improper allocation of the acquisition purchase price consideration to acquired assets and liabilities, which could result in asset impairments, the recording of previously unrecorded liabilities, and other financial statement adjustments. The difficulty in estimating the fair values of acquired assets and liabilities is increased during periods of economic uncertainty.

Asset Retirement Obligation

We recognize the fair value of asset retirement obligations (“AROs”) in the period in which a determination is made that a legal obligation exists to dismantle an asset and remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated.

The liability amounts are based on future retirement cost estimates and incorporate many assumptions such as time to abandonment, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related property, plant and equipment (“PP&E”) balances. If the estimated future cost of the AROs changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased, and expense is recognized through accretion, and the capitalized cost is depreciated over the useful life of the asset. At December 31, 2023, our ARO liability was approximately $197 million. A 10% increase in the liability as of December 31, 2023 would result in a liability of $216 million, while a 10% decrease would result in a liability of $177 million.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs. Transfers between levels, if any, are recognized at the end of each reporting period. We primarily apply the market approach for recurring fair value measurement, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management’s judgments regarding expectations of projected cash flows and discounts those cash flows using a risk-adjusted discount rate.

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 classify these measurements as Level 2.

SEC Filing Status

The Company’s emerging growth company (“EGC”) status expired as of December 31, 2023, due to completing the five fiscal years following our initial public offering (“IPO”) in 2018. As of December 31, 2023, the Company will be required to adopt new or revised accounting standards when they are applicable to public companies that are not EGCs, to comply with auditor attestation requirements Section 404(b) of the Sarbanes-Oxley Act and will not have the benefit of certain reduced disclosure requirements available to EGCs.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information included or incorporated by reference in this 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 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. Therefore, such forward-looking statements involve significant risks and uncertainties that could materially affect our expected financial position, financial and operating results, liquidity, cash flows (including, but not limited to, Adjusted Free Cash Flow) and business prospects. Material risks that may affect us are discussed above in “Item 1A. Risk Factors” in this Annual Report.

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, particularly the rise to historically high levels in 2022 and 2023, and government efforts to reduce inflation, including increased interest rates;
- overall domestic and global political and economic trends, geopolitical risks and general economic and industry conditions, such as inflation, rising 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 recent Israel-Hamas conflict, 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 the Macpherson Acquisition, including the risk that we may fail to successfully integrate the assets into our operations, identify risks or liabilities associated with Macpherson Energy, 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 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 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates, which can affect our business, financial condition, operating results and cash flows. The following should be read in conjunction with the financial statements and related notes included elsewhere in this report. The Company continually monitors its market risk exposure, including the impact and developments related to the ongoing conflict in Ukraine, the Israel-Hamas conflict, increase in interest rate and inflation trend, which introduced significant volatility and uncertainties in the financial markets during 2023.

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 December 31, 2023, the fair value of our hedge positions was a net asset of less than $1 million. A 10% increase in the oil and natural gas index prices above the December 31, 2023 prices would result in a net liability of approximately $66 million; conversely, a 10% decrease in the oil and natural gas index prices below the December 31, 2023 prices would result in a net asset of approximately $75 million. For additional information about derivative activity, see Note 4, Derivatives, in the Notes to the Consolidated Financial Statements in Part II— Item 8. "Financials Statements and Supplementary Data" of this Annual Report.

At December 31, 2023, the fair value of our emission allowances required by California's cap-and-trade program was $19 million. A 10% increase or decrease in the market price would result in a change in expense by approximately $2 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.

Credit Risk

Our credit risk relates primarily to trade and other receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We actively manage this credit risk by selecting customers that we believe to be financially strong and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that customer credit risk is adequately diversified.

We had six commodity derivative counterparties at both December 31, 2023 and December 31, 2022. We did not receive collateral from any of our counterparties. We minimize the credit risk of our 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 and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated. Considering these factors together, we believe exposure to credit losses related to our business at December 31, 2023 was not material and losses associated with credit risk have not been material for all periods presented.

Interest Rate Risk

Our 2021 RBL Facility has a variable interest rate on outstanding balances. As of December 31, 2023, we had $31 million borrowings under our 2021 RBL Facility at an interest rate of 10.50%. Assuming a constant borrowing level under the Credit Facility, an increase or decrease in the interest rate of 1% would not result in a material change in the aggregate interest expense on an annual basis. As of December 31, 2023, we had no borrowings under our 2022 ABL Facility. The 2026 Notes have a fixed interest rate and thus we are not exposed to interest rate risk on these instruments. See Note 3, Debt, in the Notes to the Consolidated Financial Statements in Part II—Item 8. "Financial Statements and Supplementary Data" of this Annual Report for additional information regarding interest rates on our outstanding debt.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors Berry Corporation (bry):

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Berry Corporation (bry) and subsidiaries (the Company) as of December 31, 2023 and December 31, 2022, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control – Integrated Framework (2013* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and December 31, 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023 based on criteria established in *Internal Control – Integrated Framework (2013* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company acquired Macpherson Energy Corporation during 2023, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2023, Macpherson Energy Corporation's internal control over financial reporting associated with total assets of $129.8 million and total revenues of $14.5 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2023. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Macpherson Energy Corporation.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Estimate of proved oil and natural gas reserve quantities used in the depletion of proved oil and natural gas properties

As discussed in Note 1 to the consolidated financial statements, the Company calculates depletion for its proved oil and natural gas properties using a unit-of-production method. Under this method, capitalized acquisition and development costs of proved oil and natural gas properties are amortized over estimated proved oil and natural gas reserve quantities. The estimation of proved oil and natural gas reserve quantities requires the expertise of petroleum engineering specialists. The Company engages an independent petroleum engineering firm to estimate proved oil and natural gas reserve quantities, who are assisted by the Company's internal engineers. The Company recorded depreciation, depletion, and amortization expense of $160 million for the year ended December 31, 2023.

We identified the evaluation of the estimate of proved oil and natural gas reserve quantities used in the depletion of proved oil and natural gas properties as a critical audit matter. Complex auditor judgment was required to evaluate the key assumptions of the future production quantities and reserve classification used in the Company's estimate of proved oil and natural gas reserve quantities. Significant changes to these assumptions could impact the depletion of proved oil and natural gas properties.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion process, including controls related to determination of the future production quantities and reserve classification assumptions used by the Company to estimate proved oil and natural gas reserve quantities. We evaluated (1) the professional qualifications of the Company's internal engineers, independent petroleum engineers and independent petroleum engineering firm, (2) the knowledge, skill, and ability of the Company's internal engineers and independent petroleum engineers, and (3) the relationship of the independent petroleum engineers and independent petroleum engineering firm to the Company. We analyzed and assessed the determination of depletion expense for compliance with industry and regulatory standards. To assess the Company's ability to accurately estimate future production quantities, we compared the estimated future production quantities used by the Company in prior periods to actual production quantities. We analyzed the estimated future production quantities used by the Company in the current period against current actual production rates. We assessed compliance of the methodology used by the Company's independent petroleum engineering firm to estimate and classify proved oil and natural gas reserve quantities with industry and regulatory standards. We read and considered the report of the Company's independent petroleum engineering firm in connection with our evaluation of the Company's estimate of proved oil and natural gas reserve quantities.

Estimate of undiscounted future cash flows of proved oil and natural gas reserves used to assess the recoverability of the carrying value of certain proved oil and natural gas properties

As discussed in Note 1 to the consolidated financial statements, the Company performs recoverability tests for the carrying value of its oil and natural gas properties generally on a field-by-field basis. The recoverability tests are performed whenever events or changes in circumstance indicate that the carrying value may not be recoverable. The Company estimates the undiscounted future cash flows expected to be generated from the oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas property to determine if the carrying amount is recoverable. The determination of the undiscounted future cash flows to assess recoverability is largely driven by the underlying estimate of future proved reserve quantities and future commodity prices. During 2023, the Company identified an indicator of impairment and completed the recoverability test for two of its fields, recording no impairment. As of December 31, 2023, the carrying value of proved oil and natural gas properties was $1,066 million.

We identified the evaluation of the estimate of undiscounted future cash flows of proved oil and natural gas reserves used to assess the recoverability of the carrying value of certain of the Company's proved oil and natural gas properties as a critical audit matter. Subjective auditor judgment was required to evaluate the key assumptions of future proved reserve quantities and future commodity prices. Significant changes to these assumptions could impact the Company's determination of the recoverability of the Company's proved oil and natural gas properties.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion and impairment processes, including controls related to the determination of future proved reserve quantities and future commodity prices. We compared the proved reserve quantities used by the Company in the recoverability test to the proved reserve quantity estimates prepared by the independent petroleum engineers for depletion under the unit-of-production method. We assessed compliance of the methodology used by the Company's internal engineers to estimate future proved reserve quantities with industry and regulatory standards. We also compared the future proved reserve quantities used by the Company to historical production trends. We evaluated the professional qualifications and the knowledge, skill, and ability of the Company's internal engineers. We also tested the future commodity prices used by comparing those prices to publicly available prices.

/s/ KPMG LLP

We have served as the Company's auditor since 2013.

Dallas, Texas
March 7, 2024

BERRY CORPORATION (bry)
CONSOLIDATED BALANCE SHEETS

		December 31, 2023		December 31, 2022
		(in thousands, except share amounts)		
ASSETS				
Current assets:				
Cash and cash equivalents	$	4,835	$	46,250
Accounts receivable, net of allowance for doubtful accounts of $655 and $866 at December 31, 2023 and December 31, 2022		86,918		101,713
Derivative instruments		5,288		36,367
Other current assets		43,759		33,725
Total current assets		140,800		218,055
Noncurrent assets:				
Oil and natural gas properties		1,906,134		1,725,864
Accumulated depletion and amortization		(592,621)		(465,889)
Total oil and natural gas properties, net		1,313,513		1,259,975
Other property and equipment		167,767		155,619
Accumulated depreciation		(74,668)		(55,781)
Total other property and equipment, net		93,099		99,838
Deferred income taxes		30,308		42,844
Derivative instruments		5,463		76
Other noncurrent assets		10,975		10,242
Total assets	$	1,594,158	$	1,631,030
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$	213,401	$	203,101
Derivative instruments		9,781		31,106
Total current liabilities		223,182		234,207
Noncurrent liabilities:				
Long-term debt		427,993		395,735
Derivative instruments		959		13,642
Deferred income taxes		2,344		—
Asset retirement obligation		176,578		158,491
Other noncurrent liabilities		5,126		28,470
Commitments and Contingencies - Note 5				
Stockholders' Equity:				
Common stock ($0.001 par value; 750,000,000 shares authorized; 87,671,241 and 86,350,771 shares issued; and 75,667,430 and 75,767,503 shares outstanding, at December 31, 2023 and December 31, 2022, respectively)		88		86
Additional paid-in capital		819,157		821,443
Treasury stock, at cost (12,003,811 shares at December 31, 2023 and 10,583,268 shares at December 31, 2022)		(113,768)		(103,739)
Retained earnings		52,499		82,695
Total stockholders' equity		757,976		800,485
Total liabilities and stockholders' equity	$	1,594,158	$	1,631,030

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2023	2022	2021
	(in thousands, except per share amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 669,110	$ 842,449	$ 625,475
Services revenue	178,554	181,400	35,840
Electricity sales	15,277	30,833	35,636
Gains (losses) on oil and gas sales derivatives	40,006	(137,109)	(156,399)
Marketing revenues	—	289	3,921
Other revenues	513	479	477
Total revenues and other	903,460	918,341	544,950
Expenses and other:			
Lease operating expenses	316,726	302,321	236,048
Costs of services	141,771	142,819	28,339
Electricity generation expenses	7,079	21,839	23,148
Transportation expenses	4,486	4,564	6,897
Marketing expenses	—	299	3,811
Acquisition costs	3,338	—	—
General and administrative expenses	95,873	96,439	73,106
Depreciation, depletion and amortization	160,542	156,847	144,495
Taxes, other than income taxes	57,973	39,495	46,500
Losses (gains) on natural gas purchase derivatives	26,386	(88,795)	(38,577)
Other operating (income) expenses	(1,788)	3,722	3,101
Total expenses and other	812,386	679,550	526,868
Other (expenses) income:			
Interest expense	(35,412)	(30,917)	(31,964)
Other, net	(237)	(142)	(247)
Total other (expenses) income	(35,649)	(31,059)	(32,211)
Income (loss) before income taxes	55,425	207,732	(14,129)
Income tax expense (benefit)	18,025	(42,436)	1,413
Net income (loss)	$ 37,400	$ 250,168	$ (15,542)
Net income (loss) per share:			
Basic	$ 0.49	$ 3.19	$ (0.19)
Diluted	$ 0.48	$ 3.03	$ (0.19)

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
			(in thousands)		
December 31, 2020	$ 85	$ 915,877	$ (49,995)	$ (151,931)	$ 714,036
Shares withheld for payment of taxes on equity awards	—	(1,543)	—	—	(1,543)
Stock-based compensation	—	14,434	—	—	14,434
Issuance of common stock	1	—	—	—	1
Purchase of treasury stock	—	—	(2,441)	—	(2,441)
Dividends declared on common stock, $0.20/share	—	(16,297)	—	—	(16,297)
Net loss	—	—	—	(15,542)	(15,542)
December 31, 2021	86	912,471	(52,436)	(167,473)	692,648
Shares withheld for payment of taxes on equity awards	—	(4,136)	—	—	(4,136)
Stock-based compensation	—	17,762	—	—	17,762
Purchase of treasury stock	—	—	(51,303)	—	(51,303)
Dividends declared on common stock, $1.34/share	—	(104,654)	—	—	(104,654)
Net income	—	—	—	250,168	250,168
December 31, 2022	86	821,443	(103,739)	82,695	800,485
Shares withheld for payment of taxes on equity awards	—	(6,916)	—	—	(6,916)
Stock-based compensation	—	15,223	—	—	15,223
Issuance of common stock	2	—	—	—	2
Purchase of treasury stock	—	—	(10,029)	—	(10,029)
Dividends declared on common stock, $0.97/share	—	(10,593)	—	(67,596)	(78,189)
Net income	—	—	—	37,400	37,400
December 31, 2023	$ 88	$ 819,157	$ (113,768)	$ 52,499	$ 757,976

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Cash flow from operating activities:			
Net income (loss)	$ 37,400	$ 250,168	$ (15,542)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	160,542	156,847	144,495
Amortization of debt issuance costs	2,636	2,590	4,430
Stock-based compensation expense	14,356	16,973	13,783
Deferred income taxes	15,813	(45,566)	819
(Decrease) in allowance for doubtful accounts	(211)	—	(1,349)
Other operating expenses (income)	1,834	160	(487)
Derivatives activities:			
Total (gains) losses	(13,620)	48,314	117,822
Cash settlements received (paid) on derivatives	5,895	(88,023)	(91,634)
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	30,197	(15,409)	(15,614)
Decrease (increase) in other assets	1,002	6,725	(24,824)
(Decrease) increase in accounts payable and accrued expenses	(39,122)	36,100	4,045
(Decrease) in other liabilities	(18,065)	(7,938)	(13,456)
Net cash provided by operating activities	198,657	360,941	122,488
Cash flow from investing activities:			
Capital expenditures:			
Capital expenditures	(73,127)	(152,921)	(132,719)
Changes in capital expenditures accruals	(7,944)	14,286	482
Acquisitions, net of cash received	(94,201)	(25,917)	(50,568)
Acquisition of properties and equipment and other	—	—	(876)
Proceeds received from divestitures	—	—	14,025
Proceeds from sale of property and equipment and other	—	—	869
Net cash used in investing activities	(175,272)	(164,552)	(168,787)
Cash flow from financing activities:			
Borrowings under RBL credit facility	538,000	247,000	119,000
Repayments on RBL credit facility	(507,000)	(247,000)	(119,000)
Borrowings under 2022 ABL credit facility	—	2,000	—
Repayments on 2022 ABL credit facility	—	(2,000)	—
Dividends paid on common stock	(78,190)	(109,455)	(11,486)
Purchase of treasury stock	(10,029)	(51,303)	(2,440)
Shares withheld for payment of taxes on equity awards and other	(6,916)	(4,136)	(1,543)
Debt issuance costs	(665)	(528)	(3,506)
Net cash used in financing activities	(64,800)	(165,422)	(18,975)
Net (decrease) increase in cash and cash equivalents	(41,415)	30,967	(65,274)
Cash and cash equivalents:			
Beginning	46,250	15,283	80,557
Ending	$ 4,835	$ 46,250	$ 15,283

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

Note 1—Basis of Presentation and Significant Accounting Policies

"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"), (2) CJ Berry Well Services Management, LLC ("C&J Management") and (3) C&J Well Services, LLC ("C&J"), ("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. In July 2023, we executed an agreement to acquire Macpherson Energy Corporation and its subsidiaries, a privately held Kern County, California operator, and we closed the acquisition in September 2023 ("Macpherson Acquisition"). As of September 15, 2023, Berry LLC owns Macpherson Energy, LLC (formerly known as Macpherson Energy Corporation) and its subsidiaries ("Macpherson Energy").

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 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. 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.

Segment Reporting

The Company has two reportable segments. Reportable segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker ("CODM"), our Chief Executive Officer, in deciding how to allocate resources and assess performance.

The E&P segment consists of 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 provides wellsite services in California to oil and natural gas production companies, with a focus on well servicing, well abandonment services and water logistics.

Use of Estimates

The preparation of the accompanying consolidated financial statements in conformity with GAAP required management of the Company to make informed estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses.

Estimates that are particularly significant to the financial statements include estimates of our reserves of oil and gas; future cash flows from oil and gas properties; depreciation, depletion and amortization; asset retirement obligations; fair values of commodity derivatives; stock-based compensation; fair values of assets acquired and liabilities assumed; and income taxes.

Cash Equivalents

We consider all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

Inventories

Inventories were included in other current assets. Oil and natural gas inventories were valued at the lower of cost or net realizable value. Materials and supplies were valued at their weighted-average cost and are reviewed periodically for obsolescence.

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized, grouped by field, and amortized over the remaining life of the associated proved reserves. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in the current period. Gains or losses from the disposal of other properties are recognized in the current period. For assets acquired, we base the capitalized cost on fair value at the acquisition date. We expense expenditures for maintenance and repairs necessary to maintain properties in operating condition, as well as annual lease rentals, as they are incurred. Estimated dismantlement and abandonment costs are capitalized at their estimated net present value and amortized over the remaining lives of the related assets. Interest is capitalized only during the periods in which these assets are brought to their intended use. The amount of capitalized interest was approximately $1 million, $1 million and $2 million in 2023, 2022 and 2021, respectively. We only capitalize the interest on borrowed funds related to our share of costs associated with qualifying capital expenditures. The amount of capitalized exploratory well costs was zero for all periods presented and the amount of capitalized overhead was approximately $6 million, $6 million and $7 million in 2023, 2022 and 2021, respectively.

We evaluate the impairment of our proved oil and natural gas properties and other property and equipment generally on a field-by-field basis or at the lowest level for which cash flows are identifiable, whenever events or changes in circumstance indicate that the carrying value may not be recoverable. We reduce the carrying values of proved properties to fair value when the expected undiscounted future cash flows are less than net book value. We measure the fair values of proved properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a risk-adjusted discount rate. These inputs require significant judgments and estimates by our management at the time of the valuation which can change significantly over time. The underlying commodity prices are embedded in our estimated cash flows and are the product of a process that begins with the relevant forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors our management believes will impact realizable prices. The fair value was estimated using inputs characteristic of a Level 3 fair value measurement.

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2023 and 2022, the net capitalized costs attributable to unproved properties were approximately $248 million for both periods. The unproved amounts were not subject to depreciation, depletion and amortization until they were classified as proved properties and amortized on a unit-of-production basis.

We evaluate the impairment of our unproved oil and gas properties whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, adverse change in regulatory environment, contractual conditions or other factors, the capitalized costs of such properties would be expensed. The timing of any write-downs of unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results.

Impairment

At the end of each quarter, management assesses the carrying value of the proved oil and gas properties for impairment by considering changes in proved reserve quantities, oil and natural gas prices, operating costs, capital costs, and future drilling plans. At December 31, 2023, there was a significant decline in proved reserves quantities in two of our seven depletion units compared to December 31, 2022 due to declining prices and changes in our development plans. Reserves quantities are price sensitive and the year-over-year change in price declined over 17%. In addition, the regulatory environment continues to limit future drilling plans. For all periods presented, we did not record any impairment charges for proved and unproved properties in accordance with the relevant GAAP rules and requirements. However, if we experience further decline in price, reduction in reserve quantities, including due to a change in development plans or regulatory rulings that impact us negatively, the carrying value of these proved oil and gas properties could become partially or entirely impaired.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, cogeneration facilities, buildings, well servicing and abandonment vehicles and equipment, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These assets are recorded at cost, depreciated using the straight-line method based on expected useful lives ranging from 15 to 39 years for buildings and improvements, 3 to 30 years for cogeneration facilities, natural gas plants and pipelines, 1 to 10 years for furniture and equipment, 1 to 10 years for well servicing and abandonment vehicles and equipment and other equipment, and the salvage value is considered as applicable. Other property and equipment assets are evaluated for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

Business Combinations

The Company records business combinations using the acquisition method of accounting. Under the acquisition method of accounting, identifiable assets acquired and liabilities assumed are recorded at their acquisition-date fair values. The excess of the purchase price over the estimated fair value, if any, is recorded as goodwill. Changes in the estimated fair values of net assets recorded for acquisitions prior to the finalization of more detailed analysis, but not to exceed one year from the date of acquisition, will adjust the amount of the purchase price allocations accordingly. Measurement period adjustments are reflected in the period in which they occur.

To allocate the purchase price consideration for acquisitions, we estimate the fair values of the assets and liabilities acquired using accepted valuation methods, and, in many cases, such estimates are based on our judgments as to the future operating cash flows expected to be generated from the acquired assets throughout their estimated useful lives. Our estimates and judgments of the fair value of acquired businesses could prove to be inexact, and the use of inaccurate fair value estimates could result in the improper allocation of the acquisition purchase price consideration to acquired assets and liabilities, which could result in asset impairments, the recording of previously unrecorded liabilities, and other financial statement adjustments. The difficulty in estimating the fair values of acquired assets and liabilities is increased during periods of economic uncertainty.

For the Macpherson Acquisition that closed in September 2023, the acquired proved property, equipment and other assets and liabilities are stated at fair value, and amortization on the acquired proved oil and gas property is computed using units-of-production method over the remaining proved reserves and depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of each asset. This property was combined with an existing field for depletion purposes. For more information, see Note 10, Acquisitions and Divestitures.

Asset Retirement Obligation

We recognize the value of asset retirement obligations ("AROs") in the period in which a determination is made that a legal obligation exists to dismantle an asset and remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The liability amounts were based on future retirement cost estimates and incorporate many assumptions such as time to abandonment, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability is initially recorded, we capitalized the cost by increasing the related property, plant and equipment ("PP&E") balances. If the estimated future cost of the AROs changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased and the capitalized cost is depreciated over the useful life of the asset. Accretion expense is also recognized over time as the discounted liabilities are accreted to their expected settlement value and is included in depreciation, depletion and amortization in the statement of operations.

The following table summarizes activity in our ARO account in which approximately $177 million and $158 million were included in long-term liabilities as of December 31, 2023 and December 31, 2022, respectively, with the remaining $20 million current portion for each period included in accrued liabilities:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Beginning balance	$ 178,491	$ 163,925
Liabilities incurred including from acquisitions	10,230	3,028
Settlements and payments	(17,110)	(19,558)
Accretion expense	11,980	10,848
Reduction due to property sales	—	(1,210)
Revisions	12,987	21,458
Ending balance	$ 196,578	$ 178,491

Revenue Recognition

The majority of the Company's revenue is from the E&P business, which includes the sale of crude oil, natural gas and NGLs, as well as electricity from its cogeneration plants. The remaining revenue is generated from the well servicing and abandonment business. See Note 12, Revenue Recognition, for information regarding the Company's revenue recognition policy.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques: Level 1—using quoted prices in active markets for the assets or liabilities; Level 2—using observable inputs other than quoted prices for the assets or liabilities; and Level 3—using unobservable inputs. Transfers between levels, if any, are recognized at the end of each reporting period. We primarily apply the market approach for recurring fair value measurement, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discounts those cash flows using a risk-adjusted discount rate.

The only items on our balance sheet that would be affected by recurring fair value measurements are derivatives and the emission allowances required by California's cap-and-trade program. 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 classify these measurements as Level 2.

We use market-observable prices for assets when comparable transactions can be identified that are similar to the asset being valued. When we are required to measure fair value and there is not a market-observable price for the asset or for a similar asset then the income approach is based on management's best assumptions regarding expectations of future net cash flows. PP&E is written down to fair value if we determine that there has been an impairment in its value. The fair value is determined as of the date of the assessment using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate. However, assumptions used reflect assets highest and best use and a market participant's view of long-term prices, costs and other factors and are consistent with assumptions used in our business plans and investment decisions. We classify these measurements as Level 3.

Stock-based Compensation

We have issued restricted stock units ("RSUs") that vest over time and performance-based restricted stock units ("PSUs") that include (i) total stockholder return PSUs ("TSR PSUs") (a) awards with a market objective measured against both absolute total stockholder return ("Absolute TSR") and a relative total stockholder return ("Relative TSR") over the performance period and (b) awards with a market objective measured against only the Absolute TSR over the performance period and (ii) awards based on the Company's average cash returned on invested capital ("CROIC PSUs" and "ROIC PSUs") over the performance period. CROIC PSUs are awarded to certain Berry employees, while ROIC PSUs are awarded to certain CJWS employees. The fair value of the stock-based awards is determined at the date of grant and is not remeasured. The fair value of the RSUs, CROIC PSUs and ROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the peer group over the performance periods, as applicable. Estimates used in the Monte Carlo valuation model are considered highly complex and subjective. Compensation expense, net of actual forfeitures, for the RSUs and PSUs is recognized on a straight-line basis over the requisite service periods, which is over the awards' respective vesting or performance periods which range from one to three years.

Other Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to loss in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Electricity Cost Allocation

We own several cogeneration facilities. Our investment in cogeneration facilities has been for the express purpose of lowering steam costs in our heavy oil operations in California and securing operating control of the respective steam generation. Cogeneration, also called combined heat and power, extracts energy from the exhaust of a turbine, which would otherwise be wasted, to produce steam. Such cogeneration operations also produce electricity. We allocate steam and electricity costs to lease operating expenses based on the conversion efficiency of the cogeneration facilities plus certain direct costs of producing steam. We also allocate a portion of the electricity production costs related to the power we sell to third parties, which is reported in "electricity generation expenses" in the statement of operations.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred tax assets will not be realized. We recognize a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit).

Earnings per Share

Basic earnings (loss) per share is calculated as net income (loss) divided by the weighted-average shares of common stock outstanding during the period. Diluted earnings (loss) per share is calculated by dividing net income (loss) by the weighted-average shares of common stock outstanding, including the effect of potentially dilutive securities. For basic earnings per share ("EPS"), the weighted-average number of common stock outstanding excludes outstanding shares related to unvested restricted stock awards. For diluted EPS, the basic shares outstanding are adjusted by adding potentially dilutive securities, unless their effect is anti-dilutive. We did not have any participating securities in the periods presented.

We compute basic and diluted EPS using the two-class method required for participating securities. Common stock awards are considered participating securities when such shares have non-forfeitable dividend rights at the same rate as common stock. Our dividend rights are forfeitable, and are not considered participating securities. Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income attributable to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses.

Business and Credit Concentrations

We maintain our cash in bank deposit accounts which, at times, may exceed federally insured amounts. We have not experienced any losses in such accounts. We believe we are not exposed to any significant credit risk on our cash.

We sell oil, natural gas and NGLs to various types of customers, including pipelines, refineries and other oil and natural gas companies and electricity to utility companies. We also perform well servicing and abandonment for oil and natural gas companies. Based on the current demand for oil, natural gas, NGLs, as well as our well servicing and abandonment services and the availability of other purchasers, we believe that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition, results of operations or net cash provided by operating activities.

For the year ended December 31, 2023, our three largest customers represented approximately 41%, 20%, and 10% of our sales. For the year ended December 31, 2022, our three largest customers represented approximately 33%, 16%, and 10% of our sales. For the year ended December 31, 2021, our four largest customers represented 30%, 16%, 14% and 12% of our sales. All such customers were customers of our E&P segment and one customer was also a customer of our well servicing and abandonment segment.

At December 31, 2023, net accounts receivable including joint interest billings, from two customers represented approximately 31% and 25% of our receivables. At December 31, 2022, net accounts receivable including joint interest billings, from three customers represented approximately 33%, 16%, and 13% of our receivables.

SEC Filing Status

The Company's emerging growth company ("EGC") status expired as of December 31, 2023, due to completing the five fiscal years following our initial public offering ("IPO") in 2018. As of December 31, 2023, the Company will be required to adopt new or revised accounting standards when they are applicable to public companies that are not EGCs, to comply with auditor attestation requirements Section 404(b) of the Sarbanes-Oxley Act and will not have the benefit of certain reduced disclosure requirements available to EGCs.

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—Oil and Natural Gas Properties and Other Property and Equipment

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

	December 31, 2023	December 31, 2022
	(in thousands)	
Proved properties	$ 1,658,246	$ 1,477,791
Unproved properties	247,888	248,073
Total proved and unproved properties	1,906,134	1,725,864
Less: Accumulated depletion and amortization	(592,621)	(465,889)
Total proved and unproved properties, net	$ 1,313,513	$ 1,259,975

Other Property and Equipment

Other property and equipment consisted of the following:

	December 31, 2023	December 31, 2022(1)
	(in thousands)	
Cogeneration facilities, natural gas plants and pipelines	$ 62,818	$ 58,357
Vehicles and service equipment	55,295	50,522
Furniture and equipment	27,335	25,902
Land	13,903	13,902
Buildings and leasehold improvements	8,416	6,936
Total other property and equipment	167,767	155,619
Less: Accumulated depreciation	(74,668)	(55,781)
Total other property and equipment, net	$ 93,099	$ 99,838

(1) Certain prior period amounts have been reclassified to conform with the current period presentation. The reclassification had no impact on the balance sheet.

Note 3—Debt

The following table summarizes our outstanding debt:

	December 31, 2023	December 31, 2022	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ 31,000	$ —	variable rates 10.50% (2023) and 9.50% (2022)	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% (2023) and 8.3% (2022)	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	431,000	400,000			
Less: Debt Issuance Costs	(3,007)	(4,265)			
Long-Term Debt, net	$ 427,993	$ 395,735			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At December 31, 2023 and 2022, debt issuance costs reported in "other noncurrent assets" on the balance sheet were approximately (i) $3 million and $4 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 December 31, 2023 and 2022, 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 and $4 million, respectively.

For the years ended December 31, 2023, 2022, and 2021, the amortization expense for the 2021 RBL Facility, the 2022 ABL Facility and the 2026 Notes combined, was approximately $3 million, $2 million, and $4 million, respectively. The amortization of debt issuance costs is presented in "interest expense" on the 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 $391 million and $369 million at December 31, 2023 and 2022, 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 December 31, 2023, 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 December 31, 2023, we were in compliance with all of the debt covenants.

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 December 31, 2023, we had $31 million borrowings outstanding, $10 million in letters of credit outstanding, and approximately $159 million of available borrowing capacity under the 2021 RBL Facility.

2022 ABL Facility

Subject to satisfaction of customary conditions precedent to borrowing, as of December 31, 2023, 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 December 31, 2023, 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% in excess of 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 December 31, 2023, each of C&J and C&J Management was in compliance with all of the debt covenants.

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 December 31, 2023, 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 December 31, 2023.

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 4—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 natural gas purchased calls, we receive settlement payments for prices above the indicated weighted-average price per mmbtu, net of any deferred premium. No payment would be made or received for prices below the indicated weighted-average price per mmbtu, other than any applicable deferred premium.

For natural gas basis swaps, we make settlement payments if the difference between NWPL and Henry Hub is below the indicated weighted-average price of our contracts and receive settlement payments if the difference between NWPL and Henry Hub is above the indicated weighted-average price.

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 December 31, 2023, we have net payable deferred premiums of approximately $2 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 December 31, 2023, we had the following crude oil production and gas purchases hedges:

	Q1 2024	Q2 2024	Q3 2024	Q4 2024	FY 2025	FY 2026
Brent - Crude Oil Production						
Swaps						
Hedged volume (bbls)	1,445,118	1,429,294	1,297,749	1,254,656	1,939,125	1,151,768
Weighted-average price ($/bbl)	$ 78.94	$ 78.93	$ 76.53	$ 76.59	$ 75.14	$ 70.27
Sold Calls(1)						
Hedged volume (bbls)	182,000	182,000	184,000	184,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 91.11	$ 85.53
Purchased Puts (net)(2)						
Hedged volume (bbls)	318,500	318,500	322,000	322,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 58.53	$ 60.00
Sold Puts (net)(2)						
Hedged volume (bbls)	45,500	45,500	46,000	46,000	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ —	$ —
NWPL - Natural Gas Purchases(3)						
Swaps						
Hedged volume (mmbtu)	3,040,000	3,640,000	3,680,000	3,680,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 4.11	$ 3.96	$ 3.96	$ 3.96	$ 4.27	$ —
HH - Natural Gas Purchases(3)						
Purchased Calls						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 3.38	$ —	$ —	$ —	$ —	$ —
Gas Basis Differentials						
NWPL/HH - basis swaps(3)						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 4.10	$ —	$ —	$ —	$ —	$ —

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

(2) Purchased puts and sold puts have been presented on a net basis.

(3) The term "NWPL" is defined as Northwest Rocky Mountain Pipeline. The term "HH" is defined as Henry Hub.

In addition to the table above, in January and February 2024, we added the following sold oil swaps (Brent): 1,000 bbl/d at $78.60 beginning February 2024 through December 2024, 1,000 bbl/d at $80.00 beginning March 2024 through December 2024, 2,000 bbl/d at $75.45 beginning January 2025 through December 2025, and 2,000 bbl/d at $71.75 beginning January 2026 through December 2026.

In January 2024, we also purchased calls of 1,000 bbl/d at $105.00 beginning February 2024 through December 2024, which are in addition to the table above.

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 December 31, 2023 and 2022.

	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

	December 31, 2022			
	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	$ 66,974	$ (30,607)	$ 36,367
Commodity Contracts	Non-current assets	39,886	(39,810)	76
Liabilities:				
Commodity Contracts	Current liabilities	(61,713)	30,607	(31,106)
Commodity Contracts	Non-current liabilities	(53,452)	39,810	(13,642)
Total derivatives		$ (8,305)	$ —	$ (8,305)

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.

Gains (Losses) on Derivatives

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

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Realized gains (losses) on commodity derivatives:			
Realized (losses) on oil and gas sales derivatives	$ (28,917)	$ (126,176)	$ (142,531)
Realized gains on natural gas purchase derivatives	34,812	38,153	50,897
Total realized gains (losses) on derivatives	5,895	(88,023)	(91,634)
Unrealized gains (losses) on commodity derivatives:			
Unrealized gains (losses) on oil and gas sales derivatives	68,923	(10,933)	(13,868)
Unrealized (losses) gains on natural gas purchase derivatives	(61,198)	50,642	(12,320)
Total unrealized gains (losses) on derivatives	7,725	39,709	(26,188)
Total gains (losses) on derivatives	$ 13,620	$ (48,314)	$ (117,822)

Note 5— 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 December 31, 2023 and December 31, 2022. 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 December 31, 2023, 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; the settlement funds will be disbursed to the class from an existing escrow account in coming weeks. The Defendants continue to maintain that the claims are without merit and admit no liability in connection with the settlement.

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 Commitments

In the ordinary course of our business, we enter into certain firm commitments to secure transportation of our production, which require a minimum monthly charge regardless of whether the contracted capacity is used or not. At December 31, 2023, future net minimum payments for non-cancelable purchase obligations (excluding oil and natural gas and other mineral leases, utilities, taxes and insurance expense) were as follows:

	2024	2025	2026	2027	2028	Thereafter	Total
	(in thousands)						
Off-Balance Sheet arrangements:[1]							
Transportation contracts[2]	$ 11,517	$ 10,051	$ 8,082	$ 8,082	$ 8,083	$ 35,438	$ 81,253
Other purchase obligations[3]	8,400	8,700	—	—	—	—	17,100
Total contractual obligations	$ 19,917	$ 18,751	$ 8,082	$ 8,082	$ 8,083	$ 35,438	$ 98,353

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

(2) 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.

(3) Amounts include a drilling commitment in California, for which we are required to drill 57 wells with a minimum commitment of $17.1 million by June 2025. In September 2023, the drilling commitment was amended to defer 28 of those wells to be drilled by December 2024 (previously required to be drilled by October 1, 2023), and the remaining 29 wells to be drilled by June 2025 (previously required to be drilled by June 1, 2024).

Note 6—Stockholders' Equity

Cash Dividends

In 2023, we paid total dividends of $0.97 per share, in the form of regular fixed dividends of $0.42 per share and variable dividends of $0.55 per share. In February 2024, our Board of Directors approved a fixed cash dividend of $0.12 per share, and a variable cash dividend of $0.14 per share based on the results of the fourth quarter of 2023, each of which is expected to be paid in March 2024.

For the years ended December 31, 2023, 2022, and 2021, we paid approximately $78 million, $109 million and $11 million, respectively, in cash dividends on our common stock.

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.

Common Stock

On March 1, 2022, our Board of Directors approved the 2022 Omnibus Plan, which was subsequently approved by stockholders on May 25, 2022. The 2022 Omnibus Plan authorized the issuance of 2,950,000 shares of common stock, which amount consists of 2,300,000 shares of common stock newly reserved under the 2022 Omnibus Plan and 650,000 shares of common stock remaining available under the 2017 Omnibus Plan. While there are rewards that remain outstanding under the 2017 Omnibus Plan, since the adoption of the 2022 Omnibus Plan, no awards have been granted or may be granted in the future under the 2017 Omnibus Plan. The maximum number of shares remaining that may be issued pursuant to the 2022 Omnibus Plan is 2,631,250 as of December 31, 2023, which is the total number of shares of our common stock remaining available for issuance after counting the number of securities to be issued upon vesting of outstanding RSU and PSU awards, and counting PSUs at the maximum payout level. Shares reserved at maximum payout that do not vest at maximum are made available for future grants.

Voting Rights. Each share of common stock is entitled to one vote with respect to each matter on which holders of common stock are entitled to vote. Holders of common stock do not have cumulative voting rights.

Dividend Rights. Holders of common stock will be entitled to receive dividends, if any, as may be declared from time to time by our Board of Directors out of legally available funds.

Liquidation Rights. Upon liquidation, dissolution or winding up of the Company, holders of our common stock will be entitled to share ratably in the assets of the Company that are legally available for distribution to holders of our common stock after payment of the Company's debts and other liabilities.

Preemptive and Conversion Rights. Holders of common stock have no preemptive, conversion or other rights to subscribe for additional shares.

Registration Rights Agreement

On June 28, 2018, Berry Corp. entered into an amended and restated registration rights agreement (the "Registration Rights Agreement") with certain holders of our Common Stock and Preferred Stock in connection with our IPO.

In accordance with the Registration Rights Agreement, Berry Corp. filed a shelf registration statement with the SEC on December 10, 2018, which was declared effective on December 13, 2018. The shelf registration statement registered the resale, on a delayed or continuous basis, of all Registrable Securities that have been timely designated for inclusion by specified Holders (as defined in the Registration Rights Agreement). Generally, "Registrable Securities" includes (i) common stock and preferred stock issued by Berry Corp. in connection with the IPO to stockholders party to the Registration Rights Agreement, and (ii) preferred stock that was purchased by the participants in the rights offering noted above and (iii) common stock into which the preferred stock converts, except that "Registrable Securities" does not include securities that have been sold under an effective registration statement or Rule 144 under the Securities Act. The Registration Rights Agreement will terminate when there are no longer any Registrable Securities outstanding.

Shares Outstanding

As of December 31, 2023, there were 75,667,430 shares of common stock outstanding. Up to an additional 4,886,044 shares were issuable for unvested restricted stock units and performance restricted stock units (assuming maximum achievement of performance goals) under the Company's 2022 Omnibus Incentive Plan as of December 31, 2023.

Stock Repurchase Program

For the year ended December 31, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million. Since the program began in December 2018 through December 31, 2023, the Company had repurchased a total of 11.9 million shares, cumulatively under the stock repurchase program for approximately $114 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company may allocate a portion of Adjusted Free Cash Flow to opportunistic share repurchases.

In February 2023, the Board of Directors approved an increase of $102 million to the Company's stock repurchase authorization increasing the Company's share authority to $200 million. As of December 31, 2023, the Company's remaining total share repurchase authority 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, 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.

We repurchased approximately $51 million and $2 million of shares in 2022 and 2021, respectively.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Purchases may be commenced or suspended at any time without notice and do 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

The Company has awarded restricted stock units ("RSUs") that are solely time-based awards and performance-based restricted stock units ("PSUs") that include (i) total stockholder return PSUs ("TSR PSUs") (a) awards with a market objective measured against both absolute total stockholder return ("Absolute TSR") and a relative total stockholder return ("Relative TSR") over the performance period, (b) awards with a market objective measured against only the Absolute TSR over the performance period and (ii) awards based on the Company's average cash returned on invested capital ("CROIC PSUs" and "ROIC PSUs") over the performance period. CROIC PSUs are awarded to certain Berry employees, while ROIC PSUs are awarded to certain CJWS employees. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 200% of the TSR PSUs granted in 2023, 0% to 250% of the TSR PSUs granted in 2022 and 2021, 0% to 200% of the CROIC PSUs granted in 2023, 2022 and 2021, and 0% to 200% of the ROIC PSUs granted in 2023 and 2022. No ROIC PSUs were granted prior to 2022.

The fair value of the RSUs, CROIC PSUs and ROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the peer group over the performance periods. The expected volatility of the Company's common stock at the date of grant was estimated based on average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the then current annualized declared dividend. The risk-free interest rate assumption was based on observed interest rates consistent with the three-year performance measurement period.

For the years ended December 31, 2023, 2022, and 2021 the stock-based compensation expense was approximately $15 million, $18 million, and $14 million, respectively. For the years ended December 31, 2023 and 2022, the income tax benefit was $5 million and $2 million, respectively. For the year ended December 31, 2021, the stock-based compensation income tax benefit was not material.

The table below summarizes the activity relating to RSUs issued under the 2017 and 2022 Omnibus Plans during the year ended December 31, 2023. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at December 31, 2023 was approximately $9 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares	Weighted-average Grant Date Fair Value
	(shares in thousands)	
Non-vested at December 31, 2022	2,519	$ 6.94
Granted	1,031	$ 8.92
Vested	(1,362)	$ 6.61
Forfeited	(273)	$ 7.88
Non-vested at December 31, 2023	1,915	$ 8.11

The table below summarizes the activity relating to the PSUs issued under the 2017 and 2022 Omnibus Plans during the year ended December 31, 2023. Unrecognized compensation cost associated with the PSUs at December 31, 2023 is approximately $6 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares	Weighted-average Grant Date Fair Value
	(shares in thousands)	
Non-vested at December 31, 2022	2,601	$ 11.18
Granted	437	$ 10.72
Performance factor adjustment	49	$ 5.11
Vested	(1,145)	$ 13.61
Forfeited	(360)	$ 11.74
Non-vested at December 31, 2023	1,582	$ 8.98

Note 7—Defined Contribution Plan

We sponsor a defined contribution retirement plan (the “401(k) Plan”) under section 401(k) of the Internal Revenue Code to assist all full-time employees in providing for retirement or other future financial needs. Employees are eligible to participate in the 401(k) Plan on their date of hire. As of January 2021, the Company reinstated the Plan's matching contributions to 100% of the first 3% of compensation deferred by the participant. As of July 2021, the Company increased the Plan's matching contributions to 100% of the first 6% of compensation deferred by the participant.

We expensed approximately $6 million, $6 million, and $2 million for the years ended December 31, 2023, 2022, and 2021, respectively, under the provisions of the 401(k) Plan.

Note 8—Income Taxes

The change in our effective tax rate from (20.4)% for the year ended December 31, 2022 to 32.5% for the year ended December 31, 2023 was primarily due to recognition of U.S. federal general business credits in 2022 related to the 2021 tax period and the release of the valuation allowance in 2022. The credits are available to offset future federal income tax liabilities. The change in our effective rate from (10.0)% for the year ended December 31, 2021 to (20.4)% for the year ended December 31, 2022 was primarily due to recognition of U.S. federal general business credits in 2022 related to the 2021 tax period and release of the valuation allowance.

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Current taxes:			
Federal	$ 850	$ 642	$ —
State	2,295	1,597	581
Total current taxes	3,145	2,239	581
Deferred taxes:			
Federal	11,914	(44,053)	832
State	2,966	(622)	—
Total deferred taxes	14,880	(44,675)	832
Total current and deferred taxes	$ 18,025	$ (42,436)	$ 1,413

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
	2023	2022	2021
Federal statutory rate	21.0 %	21.0 %	21.0 %
State, net of federal tax benefit	5.8 %	6.2 %	3.7 %
Nondeductible compensation	5.5 %	1.8 %	(24.5)%
Effect of other permanent differences	(1.4)%	(0.3)%	(4.7)%
Tax credits - Prior Year	— %	(11.5)%	(29.5)%
Tax credits - Current Year	— %	— %	21.5 %
Return to provision	1.6 %	(0.3)%	(0.2)%
Change in valuation allowance	— %	(37.3)%	2.7 %
Effective tax rate	32.5 %	(20.4)%	(10.0)%

Significant components of the deferred tax assets and liabilities are as follows:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 9,300	$ 22,402
GHG liabilities and other accruals	16,027	10,728
Asset retirement obligations	53,751	48,994
Derivative instruments	(826)	2,280
Tax credits	86,410	88,908
Other	3,336	2,882
Total deferred tax assets	167,998	176,194
Deferred tax liabilities:		
Book tax differences in property basis	(140,034)	(133,350)
Total deferred tax liabilities	(140,034)	(133,350)
Net deferred tax asset	$ 27,964	$ 42,844

As of December 31, 2023, the Company had approximately $41 million of federal net operating loss ("NOL") carryforwards and $17 million state net operating loss carryforwards. The federal net operating loss carryovers have no expiration date. State net operating loss carry forwards will expire in varying amounts beginning after taxable year 2037. In addition, as of December 31, 2023, the Company had U.S. federal general business tax credit carryforwards totaling $79 million and state tax credits of $8 million ($7 million net of federal benefit), which, if unused, will begin to expire after taxable years ended 2037 and 2033, respectively.

In recording deferred income tax assets, we consider whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income of the appropriate character during the periods in which those deferred income tax assets would be deductible. We assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of the existing deferred tax assets. As of December 31, 2023, due to the positive evidence of cumulative income in recent years and the reversal of existing federal and state temporary differences, we determined there is sufficient positive evidence to conclude that it is more likely than not that our deferred tax assets are realizable.

We had no material uncertain tax positions at December 31, 2023 or 2022. We do not believe that the total unrecognized benefits will significantly increase within the next 12 months.

We are subject to taxation in the United States and various state jurisdictions. We are not currently under audit by any federal or state income tax authority. The 2020 through 2023 federal and 2019 through 2023 state tax years generally remain open to examination under the respective statute of limitations.

Note 9—Supplemental Disclosures to the Balance Sheets and Statements of Cash Flows

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

	December 31, 2023	December 31, 2022
	(in thousands)	
Prepaid expenses	$ 12,330	$ 12,330
Materials and supplies	17,021	8,976
Prepaid deposits	9,012	7,266
Oil inventories	4,098	4,036
Other	1,298	1,117
Total other current assets	$ 43,759	$ 33,725

Other non-current assets at December 31, 2023 included approximately $8 million of operating lease right-of-use assets, net of amortization and $3 million of deferred financing costs, net of amortization. At December 31, 2022, other non-current assets included approximately $6 million of operating lease right-of-use assets, net of amortization and $4 million of deferred financing costs, net of amortization.

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

	December 31, 2023	December 31, 2022
	(in thousands)	
Accounts payable - trade	$ 31,184	$ 40,286
Deferred acquisition payable[(1)]	18,999	—
Accrued expenses	55,663	85,360
Royalties payable	28,179	38,264
Greenhouse gas liability - current portion	37,945	—
Taxes other than income tax liability	6,488	6,640
Accrued interest	11,999	10,885
Asset retirement obligation - current portion	20,000	20,000
Operating lease liability	2,944	1,666
Total accounts payable and accrued expenses	$ 213,401	$ 203,101

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

At December 31, 2023, other non-current liabilities included approximately $5 million of non-current operating lease liability. At December 31, 2022, other non-current liabilities included approximately $23 million of non-current greenhouse gas liability, which was due in the fourth quarter of 2024, and $5 million of non-current operating lease liability.

Supplemental Information on the Statement of Operations

For the year ended December 31, 2023, other operating income was $2 million and mainly consisted of net property tax refunds from prior periods and a net gain on equipment sales. For the years ended December 31, 2022, and 2021, other operating expenses were $4 million and $3 million respectively. For the year ended December 31, 2022, other operating expenses mainly consisted of $2 million in royalty audit charges incurred prior to our emergence and restructuring in 2017, and approximately $2 million loss on the divestiture of the Piceance properties. For the year ended December 31, 2021, other operating expenses mainly consisted of expensing

$3 million of unamortized debt issuance costs related to the 2017 RBL facility, approximately $3 million of supplemental property tax assessments, royalty audit charges and tank rental costs, and $2 million of various other costs such as excess abandonment costs and legal fees, partially offset by approximately $2 million on the gain on the sale of properties and over $2 million of income from employee retention credits.

Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Supplemental Disclosures of Significant Non-Cash Operating Activities:			
Greenhouse gas liability - reclassification from current liability to long-term	$ —	$ 8,000	$ —
Greenhouse gas liability - reclassification from long-term to current liability	$ 37,945	$ —	$ —
Supplemental Disclosures of Significant Non-Cash Investing Activities:			
Deferred consideration payable for acquisition	$ 18,999	$ —	$ —
Material inventory transfers to oil and natural gas properties	$ 1,694	$ 2,707	$ 3,424
Supplemental Disclosures of Cash Payments (Receipts):			
Interest, net of amounts capitalized	$ 32,251	$ 29,792	$ 29,211
Income taxes payments	$ 3,282	$ 3,633	$ 699

Note 10—Acquisitions and Divestitures

Acquisitions in 2023

In September 2023, we completed the acquisition of Macpherson Energy, a privately held Kern County, California operator. The total purchase price was approximately $70 million, subject to customary purchase price adjustments. The transaction was structured such that approximately $53 million was paid at closing, including purchase price adjustments, and approximately $20 million will be paid in July 2024, subject to purchase price adjustments.

The Macpherson transaction was accounted for as a business combination under the acquisition method of accounting. When determining the fair values of assets acquired and liabilities assumed, management made significant estimates, judgments and assumptions. The assets acquired and liabilities assumed are included in the E&P segment, which are classified as Level 3. The following table represents the Company's preliminary purchase price allocation, including preliminary working capital adjustments, of the estimated fair value of the Macpherson Energy net assets as of the closing date. The Company recorded measurement period adjustments to the initial opening balance sheet.

	September 15, 2023 (As initially reported)	Measurement Period Adjustments	September 15, 2023 (As adjusted)
		(in thousands)	
Cash and cash equivalents	$ 3,845	$ —	$ 3,845
Accounts receivable, net of allowance for doubtful accounts	12,694	2,458	15,152
Other current assets	1,541	10,301	11,842
Property and equipment	76,472	(14,022)	62,450
Other noncurrent assets	1,865	(1)	1,864
Total assets acquired	96,417	(1,264)	95,153
Accounts payable and accrued expenses assumed	(15,502)	571	(14,931)
Asset retirement obligation	(7,422)	1,146	(6,276)
Other noncurrent liabilities	(434)	1	(433)
Net assets acquired	$ 73,059	$ 454	$ 73,513

The revenue and net income from Macpherson Energy was $14 million and $6 million, respectively, from the acquisition date to December 31, 2023. The unaudited pro forma information presented below has been prepared to give effect to the Macpherson Acquisition as if it had occurred at the beginning of the periods presented. The unaudited pro forma information includes the effects from the allocation of the acquisition purchase price on depreciation and amortization as well as the Macpherson Acquisition costs charged to earnings during the years ended December 31, 2023 and 2022. The unaudited pro forma information is presented for illustration purposes only and is based on estimates and assumptions the Company deemed appropriate. The following unaudited pro forma information is not necessarily indicative of the results that would have been achieved if the Macpherson Acquisition had occurred in the past, and should not be relied upon as an indication of the operating results that the Company would have achieved if the acquisition had occurred at the beginning of the periods presented, and our operating results, or the future results.

	Pro Forma Year Ended December 31,	
	2023	2022
	(unaudited) (in thousands)	
Revenue	$ 940,125	$ 1,017,536
Net income	$ 43,707	$ 288,217

We acquired Macpherson Energy because their assets are high-quality, low decline oil producing properties, and are a natural fit with our existing rural Kern County portfolio. In addition to the attractive base production, we see upside for near-term production enhancement and development opportunities.

Also in December 2023, we acquired additional highly synergistic working interests in Kern County, California, for $33 million after purchase price adjustments. This transaction, supports our overall strategic plan to efficiently maintain our California production. During 2023, we also acquired various oil and gas properties which consisted of proved properties, for approximately $10 million in aggregate. Each of these acquisitions was accounted for as an asset acquisition as substantially all of the fair value was concentrated in oil and gas property interests.

Acquisitions and Divestitures in 2022

In January 2022, we completed the divestiture of all of our natural gas properties in Colorado, which were in the Piceance basin. The divestiture closed with a loss of approximately $2 million. Our 2021 production from these properties was 1.2 mboe/d.

In February 2022, we completed the acquisition of oil and gas producing assets in the Antelope Creek area of Utah for approximately $18 million. These assets are adjacent to our existing Uinta assets and prior to our acquisition produced approximately 0.6 mboe/d.

During 2022, we also acquired various oil and gas properties, most of which consisted of unproved properties for approximately $8 million in aggregate.

Acquisitions in 2021

On October 1, 2021, we acquired one of the largest well servicing and abandonment businesses in California, which operates as CJWS. The purchase price was $53 million, including closing adjustments mainly related to working capital, which we funded with cash on hand of $51 million in 2021 and $2 million in 2022. The CJWS transaction costs were approximately $3 million. The acquired business activities are owned and operated by C&J Well Services, a wholly-owned subsidiary of Berry Corp. formed for the purposes of acquiring these businesses and establishing an independent well services and abandonment company.

The CJWS transaction was accounted for as a business combination under the acquisition method of accounting. When determining the fair values of assets acquired and liabilities assumed, management made significant estimates, judgments and assumptions. The assets acquired and liabilities assumed are included in the well servicing and abandonment segment.

The unaudited pro forma information presented below has been prepared to give effect to the CJWS acquisition as if it had occurred at the beginning of the periods presented. The unaudited pro forma information includes the effects from the allocation of the acquisition purchase price on depreciation and amortization as well as the CJWS acquisition costs charged to earnings during the 2021 period. The unaudited pro forma information is presented for illustration purposes only and is based on estimates and assumptions the Company deemed appropriate. The following unaudited pro forma information is not necessarily indicative of the results that would have been achieved if the CJWS acquisition had occurred in the past, and should not be relied upon as an indication of the operating results that the Company would have achieved if the acquisition had occurred at the beginning of the periods presented, and our operating results, or the future results.

	Pro Forma Year Ended December 31, 2021
	(unaudited) (in thousands)
Revenue	$ 664,549
Net income	$ 740

In October 2021, our E&P segment completed the sale of our Placerita Field property in the Ventura Basin in Los Angeles County, California for approximately $14 million. We recorded a gain on the sale of approximately $2 million in 2021.

Note 11—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 earnings (loss) per share.

The RSUs and PSUs are not a participating security as the dividends are forfeitable. For the years ended December 31, 2023 and December 31, 2022, 1,545,000 and 4,069,000 incremental PSU and RSU shares were included in the diluted EPS calculation, respectively. For the year ended December 2021, no incremental RSU or

PSU shares were included in the diluted EPS calculation as their effect was anti-dilutive under the "if-converted" method.

	Year Ended December 31,		
	2023	2022	2021
	(in thousands except per share amounts)		
Basic EPS calculation			
Net income (loss)	$ 37,400	$ 250,168	$ (15,542)
Weighted-average shares of common stock outstanding	76,038	78,517	80,209
Basic income (loss) per share	$ 0.49	$ 3.19	$ (0.19)
Diluted EPS calculation			
Net income (loss)	$ 37,400	$ 250,168	$ (15,542)
Weighted-average shares of common stock outstanding	76,038	78,517	80,209
Dilutive effect of potentially dilutive securities[1]	1,545	4,069	—
Weighted-average common shares outstanding - diluted	77,583	82,586	80,209
Diluted income (loss) per share	$ 0.48	$ 3.03	$ (0.19)

(1) We excluded 3.3 million of combined RSUs and PSUs from the diluted weighted-average common shares outstanding because their effect was anti-dilutive for the year ended December 31, 2021.

Note 12—Revenue Recognition

We account for revenue in accordance with the Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers*, using the modified retrospective method.

The performance obligations that are unsatisfied at the end of a reporting period relate solely to future volumes that we have yet to sell. As such, these are wholly unsatisfied performance obligations as each unit of product represents a separate performance obligation as well as a wholly unsatisfied promise to transfer a distinct good that forms part of a single performance obligation.

We derive revenue from sales of oil, natural gas and natural gas liquids ("NGL"), with the remaining revenue generated from sales of electricity, marketing activities, and, as of October 1, 2021, our a well servicing and abandonment business, CJWS. Revenue from CJWS is primarily generated from well servicing and abandonment business.

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

Oil, Natural Gas and NGLs

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

Service Revenue

We recognize service revenue from the well servicing and abandonment business upon delivery of the service to the customer. These services are consumed by our customers when they are provided on their sites. Revenue is recognized as performance obligations have been completed on a daily basis, when all of the proper customer approvals are obtained. We do not have any long-term service contracts; nor do we have revenue expected to be recognized in any future year related to remaining performance obligations or contracts with variable consideration related to undelivered performance obligations. Our contracts with customers generally require payment within 60 days following invoicing.

Electricity Sales

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

Marketing Revenue

Marketing revenue primarily includes our activities associated with transporting and marketing third-party volumes. These sales are made under the same agreements with the same purchaser as our natural gas sales discussed above. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Revenues are presented excluding costs incurred prior to transferring control of these volumes to the customer, or the costs to purchase these volumes when we are acting as the principal. The revenues and expenses related to the sale and purchase of third-party volumes are presented separately as marketing revenue and marketing expenses on the consolidated statements of operations. In January 2022, we sold our Piceance Colorado operations, which included third-party marketing activities. Historically, these activities accounted for nearly all of our marketing revenues.

Disaggregated Revenue

The following table provides disaggregated revenue for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Oil sales	$ 643,027	$ 806,631	$ 587,613
Natural gas sales	22,293	29,515	32,679
Natural gas liquids sales	3,790	6,303	5,183
Service revenue[(1)]	178,554	181,400	35,840
Electricity sales	15,277	30,833	35,636
Marketing revenues	—	289	3,921
Other revenues	513	479	477
Revenues from contracts with customers	863,454	1,055,450	701,349
Gains (losses) on oil and gas sales derivatives	40,006	(137,109)	(156,399)
Total revenues and other	$ 903,460	$ 918,341	$ 544,950

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $186 million and $184 million, and after the intercompany elimination of $7 million and $3 million, net service revenue was $179 million and $181 million for years ended December 31, 2023 and 2022, respectively.

Note 13—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. As of September 15, 2023, E&P also includes the assets, liabilities and results of operations acquired from Macpherson Energy. 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 $7 million and $3 million in revenue and expense during consolidation for the years ended December 31, 2023 and 2022, respectively.

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.

	Year Ended December 31, 2023			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(in thousands)			
Revenues[(1)]	$ 684,900	$ 185,767	$ (7,213)	$ 863,454
Net income (loss) before income taxes	$ 163,819	$ 13,462	$ (121,856)	$ 55,425
Capital expenditures	$ 64,844	$ 5,805	$ 2,478	$ 73,127
Total assets	$ 1,652,979	$ 68,670	$ (127,491)	$ 1,594,158

	Year Ended December 31, 2022			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(in thousands)			
Revenues[(1)]	$ 874,190	$ 184,448	$ (3,188)	$ 1,055,450
Net income (loss) before income taxes	$ 303,178	$ 14,747	$ (110,193)	$ 207,732
Capital expenditures	$ 141,930	$ 8,455	$ 2,536	$ 152,921
Total assets	$ 1,563,251	$ 83,461	$ (15,682)	$ 1,631,030

	Year Ended December 31, 2021			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(in thousands)			
Revenues[(1)]	$ 665,509	$ 35,840	$ —	$ 701,349
Net income (loss) before income taxes	$ 82,826	$ 1	$ (96,956)	$ (14,129)
Capital expenditures	$ 129,479	$ 1,029	$ 2,211	$ 132,719
Total assets	$ 1,450,157	$ 81,093	$ (74,771)	$ 1,456,479

(1) These revenues do not include hedge settlements.

Note 14—Leases

We account for leases in accordance with ASC 842, *Leases*, using the modified retrospective approach that requires us to determine our lease balances as of the date of adoption.

The Company determines if an arrangement is a lease at inception of the contract. If an arrangement is a lease, the present value of the related lease payments is recorded as a liability and an equal amount is capitalized as a right of use asset on the Company's balance sheet. Right of use assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. We have long-term operating leases generally for offices. The Company's estimated incremental borrowing rate, determined at the lease commencement date using the Company's average secured borrowing rate, is used to calculate present value.

Leases with an initial term of 12 months or less are not recorded on the balance sheet and the Company recognizes lease expense for these leases on a straight-line basis over the lease term.

The components of lease expense are as follows:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Lease Cost		
Operating lease cost	$ 2,526	$ 1,992
Total net lease cost	$ 2,526	$ 1,992

The following table presents the consolidated balance sheet information related to leases as of December 31, 2023 and 2022.

	As of December 31,		
	2023	2022	Balance Sheet Classification
	(in thousands)		
Leases			
Assets			
Operating lease assets	$ 7,549	$ 6,325	Other noncurrent assets
Total assets	$ 7,549	$ 6,325	
Liabilities			
Operating lease liability	$ 2,944	$ 1,666	Accounts payable and accrued expenses
Operating lease noncurrent liability	5,126	5,213	Other noncurrent liabilities
Total liabilities	$ 8,070	$ 6,879	

	As of December 31,	
	2023	2022
Long-Term and Discount Rate		
Weighted-average remaining lease term:		
Operating Lease	3.3 years	4.3 years
Weighted-average discount rate:		
Operating Lease	7 %	5 %

The following table presents a schedule of future minimum lease payments required under all operating lease agreements as of December 31, 2023.

	As of December 31,	
	2023	2022
	(in thousands)	
2024	$ 3,369	$ 1,963
2025	2,138	1,650
2026	1,864	1,542
2027	1,241	1,549
2028	313	935
Thereafter	54	—
Total lease payments	8,979	7,639
Less: Imputed interest	(909)	(760)
Total lease obligations	8,070	6,879
Less: Current obligations	(2,944)	(1,666)
Long-term lease obligations	$ 5,126	$ 5,213

Supplemental consolidated statement of cash flow information related to leases is as follows:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	$ 2,565	$ 2,128
ROU assets obtained in exchange for operating lease liabilities	$ 3,295	$ 7,956

BERRY CORPORATION (bry)
SUPPLEMENTAL OIL & NATURAL GAS DATA
(Unaudited)

The following should be read in conjunction with our Consolidated Financial Statements and Notes to Consolidated Financial Statements.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Property acquisition costs:			
Proved[1]	$ 106,427	$ 28,144	$ 1,256
Unproved	—	—	—
Exploration costs	—	—	—
Development costs[2]	72,946	148,465	153,821
Total costs incurred	$ 179,373	$ 176,609	$ 155,077

(1) Included in proved property acquisition costs for the years ended December 31, 2023, 2022 and 2021 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $9.8 million, $2.2 million and $0.4 million, respectively.

(2) Included in development costs for the years ended December 31, 2023, 2022 and 2021 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $0.4 million, $22.3 million and $32.5 million, respectively.

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities, support equipment and facilities, and natural gas plants and pipelines with applicable accumulated depreciation, depletion and amortization are presented below:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Proved properties	$ 1,781,790	$ 1,545,056
Unproved properties	247,888	248,073
Total proved and unproved properties	2,029,678	1,793,129
Less: Accumulated depreciation, depletion and amortization	(642,996)	(500,578)
Net capitalized costs	$ 1,386,682	$ 1,292,551

Results of Oil and Natural Gas Producing Activities

The results of operations for oil, natural gas and NGL producing activities (excluding items such as corporate overhead, interest costs and reorganization items, net) are presented below:

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Net revenues from production:			
Oil, natural gas and NGL sales	$ 669,110	$ 842,449	$ 625,475
Electricity sales	15,277	30,833	35,636
Other production-related revenue	—	601	4,245
Total net revenues from production(1)	684,387	873,883	665,356
Operating costs for production:			
Lease operating expenses	316,726	302,321	236,048
Electricity generation expenses	7,079	21,839	23,148
Transportation expenses	4,486	4,564	6,897
Production-related general and administrative expenses	1,002	962	1,338
Taxes, other than income taxes	57,608	39,145	46,278
Other production-related costs	—	299	3,811
Total operating costs for production	386,901	369,130	317,520
Other costs:			
Depreciation, depletion and amortization	143,694	141,022	137,991
Other operating expenses	783	734	2,353
Total other costs	144,477	141,756	140,344
Pretax income	153,009	362,997	207,492
Income tax expense	42,783	74,295	57,117
Results of operations	$ 110,226	$ 288,702	$ 150,375

(1) Excludes cash received for derivative settlements of $6 million for the year ended December 31, 2023, and excludes cash paid for derivative settlements of $88 million and $92 million for the years ended December 31, 2022 and 2021, respectively.

Income tax is calculated as if the results presented above represented a stand-alone tax filing entity by applying the current federal and state statutory tax rates to the revenues after deducting costs, and after deductions and tax credits and allowances relating to oil and gas activities that are reflected in our consolidated income tax for the period. See Note 8, Income Taxes, for additional information about income taxes.

Proved Oil, Natural Gas and NGL Reserves

The Company's proved oil, natural gas and NGL reserve quantities and the related discounted future net cash flows before income taxes are based on estimates prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with SEC regulations, proved reserves at December 31, 2023, 2022 and 2021 were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. An analysis of the change in the Company's net interests in estimated quantities of proved oil, natural gas, and NGL reserves, all of which are attributable to properties located in the United States, is shown below:

	Year Ended December 31, 2023			
	Oil mbbls	NGLs mbbls	Natural Gas mmcf	Total mboe
Total proved reserves:				
Beginning of year	98,577	2,020	59,158	110,456
Extensions and discoveries	5,449	—	—	5,449
Revisions of previous estimates	(6,398)	(1,030)	(29,371)	(12,323)
Purchases of minerals in place	8,661	—	—	8,661
Sales of minerals in place	—	—	—	—
Production	(8,574)	(155)	(3,231)	(9,267)
End of year	97,715	835	26,556	102,976
Proved developed reserves:				
Beginning of year	53,632	1,413	44,601	62,478
End of year	52,446	635	21,114	56,600
Proved undeveloped reserves:				
Beginning of year	44,945	607	14,557	47,978
End of year	45,269	200	5,442	46,376

	Year Ended December 31, 2022			
	Oil mbbls	NGLs mbbls	Natural Gas mmcf	Total mboe
Total proved reserves:				
Beginning of year	85,801	1,259	62,454	97,469
Extensions and discoveries	22,787	546	13,102	25,517
Revisions of previous estimates	(6,474)	359	1,481	(5,868)
Purchases of minerals in place	5,300	—	10,706	7,084
Sales of minerals in place	(61)	—	(24,861)	(4,205)
Production	(8,776)	(144)	(3,724)	(9,541)
End of year	98,577	2,020	59,158	110,456
Proved developed reserves:				
Beginning of year	53,452	1,209	60,351	64,720
End of year	53,632	1,413	44,601	62,478
Proved undeveloped reserves:				
Beginning of year	32,349	50	2,103	32,749
End of year	44,945	607	14,557	47,978

	Year Ended December 31, 2021			
	Oil mbbls	NGLs mbbls	Natural Gas mmcf	Total mboe
Total proved reserves:				
Beginning of year	89,935	742	25,599	94,943
Extensions and discoveries	2,937	60	2,593	3,429
Revisions of previous estimates	1,734	598	40,574	9,094
Purchases of minerals in place	48	—	—	48
Sales of minerals in place	(24)	—	—	(24)
Production	(8,829)	(141)	(6,312)	(10,022)
End of year	85,801	1,259	62,454	97,469
Proved developed reserves:				
Beginning of year	51,249	742	25,599	56,257
End of year	53,452	1,209	60,351	64,720
Proved undeveloped reserves:				
Beginning of year	38,686	—	—	38,686
End of year	32,349	50	2,103	32,749

The tables above include changes in estimated quantities of natural gas reserves shown in boe using the ratio of six mcf to one barrel.

Proved reserves decreased by approximately seven mmboe to approximately 103 mmboe for the year ended December 31, 2023. The year ended December 31, 2023 included 12 mmboe of negative overall revisions of previous estimates, including one mmboe in California and 11 mmboe Utah. The negative overall revisions included one mmboe in California due to changes to timing of development plans, offset by positive revisions based on sidetracks and workovers that were identified, eight mmboe in Utah partly due to a change in timing of development plans and three mmboe in Utah due to net negative price revisions. In 2023, we acquired nine mmboe of proved reserves through the Macpherson Acquisition and a small acquisition in Kern County in December 2023. We added five mmboe to proved reserves from extensions in our California properties, primarily in the Hill Belridge Field, due to an increase in our proved acreage based on drilling activity.

Proved reserves increased by approximately 13 mmboe to approximately 110 mmboe for the year ended December 31, 2022. The year ended December 31, 2022 included six mmboe of negative overall revisions of previous estimates. In 2022, we experienced negative revisions of seven mmboe in California, which was partially offset by positive revisions of one mmboe in Utah. The negative other revisions resulted primarily from a change in development plans in our thermal Diatomite in our North Midway-Sunset field. Positive price-driven revisions were two mmboe, due to the increase in commodity prices. Extensions and discoveries added 26 mmboe to proved reserves. In January of 2022, we divested our Piceance basin properties and removed approximately four mmboe of proved reserves in Colorado. In February of 2022, we acquired Antelope Creek and we added seven mmboe of proved reserves in Utah.

Proved reserves increased by approximately two mmboe to approximately 97 mmboe for the year ended December 31, 2021. The year ended December 31, 2021 included nine mmboe of positive overall revisions of previous estimates. Positive price-driven revisions were 18 mmboe, due to the increase in commodity prices. In 2021, we experienced negative technical revisions of 10 mmboe in California, which was partially offset by positive technical revisions of one mmboe in the Rockies. The negative technical revisions resulted primarily from a strategic change in development plans in our Hill Tulare properties to a more focused approach on infill drilling rather than extending our proved developed area, as well as adjustments made to our thermal Diatomite development plans. Extensions and discoveries added three mmboe to proved reserves.

Standardized Measure of Discounted Future Net Cash Flows

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. See Note 8, Income Taxes, for additional information about income taxes.

	Year Ended December 31,		
	2023	2022	2021
	(in thousands, except for prices)		
Future cash inflows	$ 7,674,494	$ 9,501,374	$ 5,879,599
Future production costs	(3,439,939)	(3,909,452)	(2,589,043)
Future development costs(1)	(964,768)	(1,068,890)	(808,295)
Future income tax expenses(2)	(620,822)	(1,000,268)	(484,358)
Future net cash flows	2,648,965	3,522,764	1,997,903
10% annual discount for estimated timing of cash flows	(966,331)	(1,448,999)	(764,632)
Standardized measure of discounted future net cash flows	$ 1,682,634	$ 2,073,765	$ 1,233,271
Representative prices:(3)			
Brent Oil (bbl)	$ 82.84	$ 100.25	$ 69.47
Henry Hub Natural gas (mmbtu)	$ 2.63	$ 6.40	$ 3.64

(1) Future development costs includes site restoration and abandonment costs.

(2) Future income tax expenses are based on current statutory rates, adjusted for the tax basis of oil and gas properties and applicable tax credits, deductions and allowances.

(3) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

The following table summarizes the changes in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2023	2022	2021
	(in thousands)		
Standardized measure—beginning of year	$ 2,073,765	$ 1,233,271	$ 516,179
Net change in sales and transfer prices and production costs related to future production	(693,656)	830,294	1,140,342
Changes in estimated future development costs	90,300	42,747	8,215
Sales and transfers of oil, natural gas and NGLs produced during the period	(289,925)	(496,069)	(336,031)
Net change due to extensions, discoveries and improved recovery	110,521	476,114	56,504
Purchase of minerals in place	207,575	139,637	830
Sales of minerals in place	—	(14,684)	(5)
Net change due to revisions in quantity estimates	(294,382)	(182,173)	217,921
Previously estimated development costs incurred during the period	11,765	30,358	48,488
Accretion of discount	262,380	151,334	52,015
Changes in production rates and other	20,537	132,917	(195,093)
Net change in income taxes	183,754	(269,981)	(276,094)
Net (decrease) increase	(391,131)	840,494	717,092
Standardized measure—end of year	$ 1,682,634	$ 2,073,765	$ 1,233,271

The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company's oil and gas properties. The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

The following table summarizes the average sales price and production costs:

	Year Ended December 31,		
	2023	2022	2021
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 75.05	$ 91.98	$ 66.57
Natural gas ($/mcf)	$ 6.94	$ 7.96	$ 5.27
NGLs ($/bbl)	$ 24.47	$ 43.85	$ 36.64
Production costs (per boe):			
Lease operating expenses	$ 34.21	$ 31.72	$ 23.60

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, 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 December 31, 2023. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2023 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with GAAP.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2023, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2023. Macpherson Energy was excluded from the scope of the Company's internal control over financial reporting assessment.

The effectiveness of our internal control over financial reporting as of December 31, 2023 has been audited by KPMG LLP, an independent registered public accounting firm, who also audited our financial statements. Their attestation report is included in Part II—Item 8. "Financial Statements and Supplementary Data" of this Annual Report.

Changes in the Company's Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2023 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

Trading Plans

During the three months ended December 31, 2023, 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.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item 10 is incorporated herein by reference to our definitive Proxy Statement, for the 2024 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2023.

Our Board of Directors has adopted a Code of Business Conduct and Ethics ("Code of Conduct") applicable to all officers, directors and employees, which is available on our website (*www.bry.com/sustainability/governance*). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Conduct by posting such information within four business days following the date of the amendment or waiver on our website at the address specified above.

Item 11. Executive Compensation

The information required by this Item 11 is incorporated herein by reference to our definitive Proxy Statement, for the 2024 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2023.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information required by this Item 12 is incorporated herein by reference to our definitive Proxy Statement, for the 2024 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2023.

Securities Authorized for Issuance Under Equity Compensation Plans

On June 27, 2018, our Board of Directors approved the 2017 Omnibus Plan. A description of the plans can be found in Note 6, Stockholders' Equity in the Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. On March 1, 2022, our Board of Directors approved the 2022 Omnibus Plan, which was subsequently approved by stockholders on May 25, 2022. The 2022 Omnibus Plan authorized the issuance of an additional 2,300,000 shares of common stock, bringing the total between the 2017 Omnibus Plan and the 2022 Omnibus Plan to 12,300,000 shares. There have been approximately 9,700,000 shares issued or reserved through December 31, 2023.

The following table summarizes information related to our equity compensation plans under which our equity securities are authorized for issuance as of December 31, 2023:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights (#)(1)	Weighted-Average Exercise Price of Outstanding Options and Rights ($)(2)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (#)(3)
Equity compensation plans not approved by security holders(4)	1,936,044	N/A	—
Equity compensation plans approved by security holders(5)	2,950,000	N/A	2,631,250
Total	4,886,044	N/A	2,631,250

(1) This column reflects the number of shares of our common stock subject to outstanding restricted stock unit ("RSU") awards and performance-based restricted stock unit ("PSU") awards as of December 31, 2023, after counting the outstanding PSU awards at the maximum payout level. Because the number of shares to be issued upon settlement of outstanding PSU awards is subject to performance conditions, the number of shares actually issued may be substantially less than the number reflected in this column. No options or warrants have been granted under the 2022 Omnibus Plan.

(2) No options or warrants have been granted under the 2022 Omnibus Plan, and the RSU and PSU awards reflected in column (a) are not reflected in this column, as they do not have an exercise price.

(3) This column reflects the total number of shares of our common stock remaining available for issuance under the 2022 Omnibus Plan as of December 31, 2023, after counting the number of securities to be issued upon vesting of outstanding RSU and PSU awards as of December 31, 2023, and counting PSUs at the maximum payout level. Shares reserved at maximum payout that do not vest at max are made available for future grants.

(4) In connection with our initial public offering, our Board of Directors approved the 2017 Omnibus Plan, effective June 27, 2018. The 2017 Omnibus Plan allowed us to grant equity-based compensation awards (including stock options, stock appreciation rights, restricted stock, restricted stock units, stock awards, dividend equivalents and other types of awards) with respect to up to 10,000,000 shares of common stock (which number includes the number of shares of common stock previously issued pursuant to an award (or made subject to an award that has not expired or been terminated) under prior plans), to employees, consultants and directors of the Company and its affiliates who perform services for the Company. While there are awards that remain outstanding under the 2017 Omnibus Plan, since the adoption of the 2022 Omnibus Plan, no awards have been granted or may be granted in the future under the 2017 Omnibus Plan.

(5) On March 1, 2022, our Board of Directors approved the 2022 Omnibus Plan, which was subsequently approved by stockholders on May 25, 2022. The 2022 Omnibus Plan authorized the issuance of 2,950,000 shares of common stock, which amount consists of 2,300,000 shares of common stock newly reserved under the 2022 Omnibus Plan and 650,000 shares of common stock remaining available under the 2017 Omnibus Plan.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this Item 13 is incorporated herein by reference to our definitive Proxy Statement, for the 2024 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2023.

Item 14. Principal Accounting Fees and Services

Our independent registered public accounting firm is KPMG LLP, Dallas, TX, Auditor Firm ID: 185.

The information required by this Item 14 is incorporated herein by reference to our definitive Proxy Statement, for the 2024 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2023.

Part IV

Item 15. Exhibits

Exhibit Number	Description
2.1	Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC, dated January 25, 2017 (incorporated by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.1	Second Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 of Form 8-K filed February 19, 2020)
3.2	Fourth Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.1 of Form 8-K filed January 25, 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 of Form 8-K filed July 30, 2018)
4.1	Form of Common Stock Certificate of Berry Petroleum Corporation (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
4.2	Form of Series A Convertible Preferred Stock Certificate of Berry Petroleum Corporation (incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
4.3	Indenture, dated as of February 8, 2018, among Berry Petroleum Company, LLC, as issuer, Berry Petroleum Corporation, the other guarantors from time to time party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
4.4*	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 Association), as trustee
4.5*	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
4.6	Description of Registrant's Securities Registered Under Section 12 of the Exchange Act of 1834 (incorporated by reference to Exhibit 4.4 to the Company's Annual Report on Form 10-K filed February 27, 2020)
10.1	Amended and Restated Registration Rights Agreement, dated June 28, 2018, among Berry Petroleum Corporation and the holder party thereto (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.2†	Executive Chair Agreement by and between Berry Petroleum Company, LLC and Arthur "Trem" Smith, effective January 1, 2023 (incorporated by reference to Exhibit 10.1 of Form 8-K filed November 30, 2022)

Exhibit Number	Description
10.3†	Second Amended and Restated Executive Employment Agreement by and between Berry Petroleum Company, LLC and Cary D. Baetz, effective March 1, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed March 30, 2020)
10.4†	Second Amended and Restated Executive Employment Agreement by and between Berry Petroleum Company, LLC and Danielle Hunter, effective January 1, 2023. (incorporated by reference to Exhibit 10.3 of Form 8-K filed November 30, 2022)
10.5†	Amended and Restated Employment Agreement by and between Berry Petroleum Company, LLC and Fernando Araujo, effective January 1, 2023. (incorporated by reference to Exhibit 10.2 of Form 8-K filed November 30, 2022)
10.6†	Amended and Restated Employment Agreement by and between Berry Petroleum Company, LLC and Mike Helm, effective January 1, 2023. (incorporated by reference to Exhibit 10.4 of Form 8-K filed November 30, 2022)
10.7†	Amended and Restated Berry Petroleum Corporation 2017 Omnibus Incentive Plan, dated March 7, 2018 (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.8†	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Employees other than Executive Vice Presidents (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.9†	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Executive Vice Presidents (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.10†	Berry Petroleum Corporation Form of Director Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.11†	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Employees other than Executive Vice Presidents (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 (File No. 333-226011)
10.12†	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Executive Vice Presidents (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1 (File No. 333-226011)
10.13†	Second Amended and Restated Berry Petroleum Corporation 2017 Omnibus Incentive Plan, dated June 27, 2018 (incorporated by reference to Exhibit 4.3 of S-8 Registration Statement (File No. 333-226582))
10.14†	Berry Petroleum Corporation 2017 Omnibus Incentive Plan dated June 15, 2017 (incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.15†	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Employees other than Executive Officers (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 8, 2019)
10.16†	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed March 8, 2019)
10.17†	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Directors (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K filed March 8, 2019)

Exhibit Number	Description
10.18†	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Employees other than Executive Officers (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K filed March 8, 2019)
10.19†	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.23 to the Company's Annual Report on Form 10-K filed March 8, 2019)
10.20†	Berry Corporation (bry) 2022 Omnibus Incentive Plan, dated March 1, 2022 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed May 4, 2022)
10.21†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Total Shareholder Return Performance Criteria (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed May 4, 2022)
10.22†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with CROIC Performance Criteria (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed May 4, 2022)
10.23†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with C&J Well Services ROCI Performance Criteria (Executive Employment Agreement) (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed May 4, 2022)
10.24†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with C&J Well Services ROCI Performance Criteria (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed May 4, 2022)
10.25†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Restricted Stock Unit Award Agreement for Executives (incorporated by reference to Exhibit 10.26 of the Company's Annual Report on Form 10-K filed February 27, 2023)
10.26†	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Absolute Total Shareholder Return Performance Criteria (incorporated by reference to Exhibit 10.27 of the Company's Annual Report on Form 10-K filed February 27, 2023)
10.27†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Restricted Stock Unit Award Agreement for Executives (2024)
10.28†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Restricted Stock Unit Award Agreement for Executives without Employment Agreement (2024)
10.29†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Absolute Total Shareholder Return Performance Criteria for Executives (2024)
10.30†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Absolute Total Shareholder Return Performance Criteria for Executives without Employment Agreement (2024)
10.31†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Relative Total Shareholder Return Performance Criteria for Executives (2024)
10.32†*	Berry Corporation (bry) 2022 Omnibus Incentive Plan - Form of Performance-Based Restricted Stock Unit Award Agreement with Relative Total Shareholder Return Performance Criteria for Executives without Employment Agreement (2024)

Exhibit Number	Description
10.33	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.34	Credit Agreement, dated as of August 26, 2021, by and among Berry Petroleum Company, LLC, as borrower, Berry Corporation (bry), JPMorgan Chase Bank, N.A., as administrative agent and an issuing bank, and each of the lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed August 27, 2021)
10.35	First Amendment to Credit Agreement, dated as of December 8, 2021, 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 10.1 of Form 8-K filed December 10, 2021)
10.36	Second Amendment to Credit Agreement and Limited Consent and Waiver, dated as of May 2, 2022, 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 10.6 of the Quarterly Report on Form 10-Q filed May 4, 2022)
10.37	Third Amendment to Credit Agreement dated as of May 27, 2022, 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 10.1 of Form 8-K filed June 1, 2022)
10.38	Revolving Loan and Security Agreement, dated as of August 9, 2022, 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, and related Promissory Note, dated August 9, 2022, issued by C&J Well Services, LLC, as a borrower, and CJ Berry Well Services Management, LLC, as a borrower, to Tri Counties Bank, as lender (incorporated by reference to Exhibit 10.35 of the Company's Annual Report on Form 10-K filed February 28, 2023)
10.39	Amendment to Revolving Loan and Security Agreement, dated as of March 14, 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 10.1 of the Company's Quarterly Report on Form 10-Q filed May 3, 2023)
10.40	Fourth Amendment to the Credit Agreement dated as of May 10, 2023, 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 10.1 of Form 8-K filed May 12, 2023)
10.41	Fifth Amendment to the Credit Agreement dated as of November 3, 2023, 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 10.1 of Form 8-K filed November 9, 2023)
10.42*	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
10.43*	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
21.1*	List of Subsidiaries of Berry Corporation (bry)
23.1*	Consent of KPMG LLP
23.2*	Consent of DeGolyer and MacNaughton
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

Exhibit Number	Description
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1*	Berry Corporation (bry) Clawback Policy
99.1*	Report as of December 31, 2023 of DeGolyer and MacNaughton
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.

(**) Furnished herewith.

(†) Indicates a management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

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*" which is defined as cash flow from operations less regular fixed dividends and maintenance capital. In January 2024, we updated the definition of Adjusted Free Cash Flow to 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.

"b*tu*" 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 Section 13 or 15(d) 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)

Date: March 7, 2024

/s/ Fernando Araujo

Fernando Araujo
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
March 7, 2024	/s/ Fernando Araujo Fernando Araujo	Chief Executive Officer and Director (Principal Executive Officer)
March 7, 2024	/s/ Michael S. Helm Michael S. Helm	Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)
March 7, 2024	/s/ Renée Hornbaker Renée Hornbaker	Chair
March 7, 2024	/s/ A.T. Smith A.T. “Trem” Smith	Director
March 7, 2024	/s/ Anne L. Mariucci Anne L. Mariucci	Director
March 7, 2024	/s/ Donald L. Paul Donald L. Paul	Director
March 7, 2024	/s/ Rajath Shourie Rajath Shourie	Director
March 7, 2024	/s/ James M. Trimble James M. Trimble	Director

EXECUTIVE OFFICERS

FERNANDO ARAUJO
Chief Executive Officer

DANIELLE HUNTER
President

MIKE HELM
Vice President, Chief Financial Officer & Chief Accounting Officer

DIRECTORS

FERNANDO ARAUJO
Chief Executive Officer
Berry Corporation

RENÉE HORNBAKER (1C) (2) (3)
Board Chair
Chief Executive Officer of Storey & Gates LLC

ANNE MARIUCCI (1) (2C) (3)
Independent Director
General Partner of MFLP

(C) Committee Chair
(1) Audit Committee
(2) Compensation Committee
(3) Nominating & Governance Committee

DONALD PAUL (3)
Independent Director
Executive Director of the Energy Institute,
The William M. Keck Chair of Energy Resources & Research,
Professor of Engineering at the University of Southern California

RAJATH SHOURIE (1) (2)
Independent Director
Retired

JAMES TRIMBLE (1) (2) (3C)
Independent Director
Chair of Tanda Resources LLC

INVESTOR RELATIONS

TODD CRABTREE
Berry Corporation
16000 N. Dallas Parkway, Suite 500
Dallas, TX 75248
(661) 616-3811 ir@bry.com

TRANSFER AGENT/REGISTRAR

EQ
P.O. Box 64874
St. Paul, MN 55164-0874

Shareowner Services
(800) 468-9716
shareowneronline.com

SECURITIES

Berry Common Stock is traded on Nasdaq under the symbol BRY.

ANNUAL REPORT ON FORM 10-K FOR 2023

Our Form 10-K is included in this document in its entirety as filed with the SEC. Upon request to Investor Relations, we will deliver free of charge a copy of our Form 10-K.

TOTAL SHAREHOLDER RETURN PERFORMANCE GRAPH

Page 2 of this annual report includes a performance graph comparing the cumulative total return to shareholders on our common stock relative to the cumulative total returns of the S&P SmallCap 600,® the Dow Jones US Exploration & Production indexes and the Vanguard Energy ETF (with reinvestment of all dividends).

DIVIDEND PAYMENT DATES – 2024

Any dividend declared by the Board will be paid on such dates established by the Board.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP
Dallas, TX
kpmg.com

CAUTIONARY NOTE ON FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements involving risks and uncertainties that could materially affect our expected results of operations, financial position, liquidity, cash flows, business strategy and business prospects, including potential growth opportunities, development and production plans, capital requirements, expected production and costs, reserves, hedging activities, return of capital, and other guidance. Factors (but not necessarily all the factors) that could cause actual results to differ from anticipated results include: commodity price volatility; legislative and regulatory actions that may prevent, delay or otherwise restrict our ability to drill and develop our assets, including with respect to existing and/or new requirements in the regulatory approval and permitting process; legislative and regulatory initiatives in California or our other areas of operation addressing climate change or other environmental concerns; investment in and development of competing or alternative energy sources; drilling, production and other operating risks; effects of competition; uncertainties inherent in estimating natural gas and oil reserves and in projecting future rates of production; our ability to replace our reserves through exploration and development activities or strategic transactions; cash flow and access to capital; the timing and funding of development expenditures; environmental, health and safety risks; effects of hedging arrangements; potential shut-ins of production due to lack of downstream demand or storage capacity; disruptions to, capacity constraints in, or other limitations on the third-party transportation and market takeaway infrastructure (including pipeline systems) that deliver our oil and natural gas and other processing and transportation considerations; 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; the ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; our ability to successfully integrate the Macpherson assets into our operations; we fail to identify risks or liabilities related to Macpherson, its operations or assets; our inability to achieve anticipated synergies; our ability to successfully execute other strategic bolt-on acquisitions; overall domestic and global political and economic conditions; 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 Israel-Hamas conflict, or a prolonged recession; inflation levels and government efforts to reduce inflation, including increased interest rates and volatility in financial markets and banking; changes in tax laws; information technology failures or cyberattacks; and other material risks that appear in "Item 1A – Risk Factors" of our Form 10-K and other periodic reports filed with the SEC.

bry

BERRY
CORPORATION

INVESTOR RELATIONS
Berry Corporation
16000 N. Dallas Parkway, Suite 500, Dallas, TX 75248
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