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, 2021

OR

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

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

BERRY CORPORATION (bry)
(Exact name of registrant as specified in its charter)

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

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

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

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

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. ☐

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 $362.7 million.

Shares of common stock outstanding as of February 28, 2022: 80,313,320

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held May 25, 2022) will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2021 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 three 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 ("CJWS"). As the context may require, the "Company", "we", "our" or similar words refer to Berry Corp. and its consolidated subsidiary, Berry LLC, and as of October 1, 2021 this also includes CJWS and C&J Management.

As of October 1, 2021, we have operated in two business segments: (i) development and production ("D&P") (ii) well servicing and abandonment. The development and production segment is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah. On October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California, which became a reportable segment (well servicing and abandonment) under U.S. GAAP.

Our Company

We are a western United States independent upstream energy company focused on the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California. As further discussed below, in the fourth quarter of 2021, we diversified our operations with the acquisition of a business with well servicing and abandonment capabilities.

Our upstream development and production assets, in the aggregate, are characterized by high oil content, with 100% oil content for our California assets, and are in rural areas with low population. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. For example, the cost to drill and complete the different types of our wells in California is approximately $400,000 per well. The vertical wells in Utah operations cost approximately $1.5 million per well. In contrast, wells in typical unconventional resource plays cost $5 million to $10 million to drill and complete. The California oil market has Brent-linked pricing which in recent history realizes premium pricing to WTI. In the past five years Brent pricing has averaged almost $5 above WTI. All of our California assets are located in the 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 substantial data produced over the basin's long history, its reservoir characteristics are well understood, which enables predictable, repeatable, low geological risk and low-cost development opportunities. We also have upstream assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah. In January 2022, we divested our natural gas properties in the Piceance basin of Colorado.

In the fourth quarter of 2021, we acquired one of the largest upstream well servicing and abandonment businesses in California, which operates as C&J Well Services. This acquisition creates a strategic growth opportunity for Berry. It 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 Well Services is critical to advancing our strategy to work with the State of California to reduce fugitive emissions - including methane and carbon dioxide - from idle wells. We believe that C&J Well Services is uniquely positioned to capture both state and federal funds to help remediate orphan idle wells (an idle well that has been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well), and there are approximately 35,000 idle wells estimated to be in California according to third-party sources.

Since our Initial Public Offering in 2018, we have demonstrated our commitment to returning a substantial amount of capital to shareholders, delivering $134 million to our shareholders through dividends and share repurchases through 2021. In 2022, we initiated a new shareholder return model, which is designed to significantly increase cash returns to our shareholders from our discretionary free cash flow, which we define as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. Like our business model, this new shareholder returns model is simple and further demonstrates our commitment to return capital to our shareholders.

We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling locations with attractive full-cycle economics will support our objectives to generate Levered Free Cash Flow to fund our operations, optimize capital efficiency, and return meaningful capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles. "Levered Free Cash Flow" is a non-GAAP financial measure defined as Adjusted EBITDA less capital expenditures, interest expense and dividends. "Adjusted EBITDA" is also a non-GAAP financial measure defined as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual and infrequent items. These supplemental non-GAAP financial measures are used by management and external users of our financial statements. Please see "Management's Discussion and Analysis—"Non-GAAP Financial Measures" for reconciliations of Levered Free Cash Flow and Adjusted EBITDA to net cash provided by operating activities and of Adjusted EBITDA to net income (loss), our most directly comparable financial measure calculated and presented in accordance with GAAP.

We have a progressive approach to growing and evolving our businesses in today's dynamic oil and gas industry. Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safe, more efficient and lower emission operations. As part of our commitment to creating long-term value for our stockholders, we are dedicated to conducting our operations in an ethical, safe and responsible manner, to protecting the environment, and to 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 are determined to be part of the solution.

The Berry Advantage

Our business model is similar to that of a manufacturer. The foundation of our business model is our base production, which is the production that comes from our existing, producing wells. In terms of maintaining California production levels year over year, our base production, on average, accounts for 90% of our total annual production, and the remaining 10% comes from the drilling of new wells or the workover of existing wells. We also have a manageable annual corporate decline rate of approximately 13%, with abundant inventory of new drill and workover opportunities and predictable costs, all which provides clear visibility to our potential cash flow. Over the price cycle these advantages allow us to generate significant cash flow.

We believe the following competitive advantages will allow us to successfully execute our business strategy and to meet our objectives to generate Levered Free Cash Flow to fund our operations, optimize capital efficiency, and return meaningful capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles:

- ***Stable, long-lived, oil-weighted conventional asset base with low and predictable production decline rates.*** The overwhelming majority of our interests are in properties that have produced oil for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. The properties, especially our California assets, 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. For example, our current corporate annual decline rate is approximately 13%. One advantage of our decline curve is that it provides strong visibility into our cash flows and it is manageable. In California, production from existing wells, which requires little to no additional capital to continue to produce, provides on average 90% of the production needed to maintain existing levels. The nature of our assets also provides us with significant capital flexibility (discussed further below) and an ability to efficiently hedge material quantities of future expected production allowing for stronger viability to our cash flow compared to the typical resource play.

- ***Extensive inventory of low geological risk identified drilling opportunities with attractive full-cycle economics, high operational control and a stable development and production cost environment provides capital flexibility.*** We expect to be able to generate attractive rates of return and positive Levered Free Cash Flow through typical commodity price cycles, which, if prolonged, would allow us to continue returning meaningful capital to stockholders, maintain current production levels and fund organic and strategic growth, among other things. For example, our proved undeveloped ("PUD") reserves in California are projected to average single-well rates of return of approximately 60% based on the assumptions prepared by DeGolyer and MacNaughton in our SEC reserves report as of December 31, 2021. These margins would be substantially greater based on the current strip prices which are more than 15% higher presently than the prices used for the 2021 reserve calculation. We currently operate approximately 98% of our producing wells and we expect this level of control to continue for our identified gross drilling locations. In addition, a substantial majority of our acreage is currently held by production and 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 our capital expenditures, technological enhancements and marketing of production. Also, unlike many of our peers who operate primarily in unconventional plays, our assets generally do not necessitate supply-constrained and highly specialized equipment, which provides us relative insulation from service cost inflation pressures. Our high degree of operational control and relatively stable and predictable cost environment provide us significant visibility and understanding of our expected cash flow.

- ***Brent-influenced crude oil pricing advantage.*** California oil prices are Brent-influenced as California refiners import approximately 65% to 70% of the state's demand from OPEC+ countries and other waterborne sources. Without the higher costs and potential environmental impact associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing should continue to allow us to realize positive cash margins in California over the typical commodity price cycles.

- ***Simple capital structure and conservative balance sheet leverage with ample liquidity and minimal contractual obligations.*** Since our 2018 IPO, our capital structure has consisted of common stock and $400 million of 7.0% senior unsecured notes due February 2026 (the "2026 Notes"). As of December 31, 2021, we had $215 million of liquidity, consisting of $22 million of cash on hand and $193 million available for borrowings under our 2021 RBL Facility. As of December 31, 2021, our unhedged Leverage Ratio (as defined in our RBL Facility) was 2.0:1.0. In addition, we have minimal long-term service or fixed-volume delivery commitments. This liquidity and flexibility permit us to capitalize on opportunities that may arise to strategically grow and increase stockholder value.

- ***Experienced, 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 deep technical, operational and strategic management experience to optimize the value of our assets and the Company. We are focused on the principles of operating within Levered Free Cash Flows while maintaining or growing our production and growing the value of our reserves. In doing so, we take 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 Strategy

The principal elements of our business strategy include the following:

- ***Operate within Levered Free Cash Flow and maintain balance sheet strength and flexibility through commodity price cycles.*** We are committed to operating within Levered Free Cash Flow, which includes funding our capital program and paying interest and fixed dividends, as declared by our Board of Directors. Additionally, our objective is to achieve and maintain a long-term, through-cycle unhedged Leverage Ratio (as defined in our RBL Facility) between 1.0x and 2.0x, or lower.

- ***Return capital to our stockholders.*** Our objective is to take advantage of our strong base production and the visibility into our cash flow to maintain disciplined value creation and a returns-focused approach to capital allocation in order to generate excess free cash flow. Since our 2018 IPO through December 31, 2021, we have returned approximately $134 million to our shareholders through dividends and share repurchases, representing 122% of our IPO proceeds. Through December 31, 2021, we repurchased approximately 7% of our outstanding shares for approximately $52 million leaving approximately $48 million authorized and available for future repurchases under the program. Additionally, in February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes, although we have not yet repurchased any notes under this program. For a discussion of our dividend policy, as well as our stock repurchase program, please see "Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

  In the fourth quarter of 2021, we announced a new shareholder return model, which went into effect January 1, 2022, designed to increase cash returns to our shareholders, further demonstrating our commitment to be a leading returner of capital to its shareholders. The model is based on our discretionary free cash flow, which is defined as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. Under this new model, we intend to allocate discretionary free cash flow on a quarterly basis as follows:

  - 60% predominantly in the form of cash variable dividends to be paid quarterly, as well as opportunistic debt repurchases; and

  - 40% in the form of discretionary capital, to be used for opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention

- ***Grow or maintain production and reserves in a capital efficient manner while producing positive internally generated Levered Free Cash Flow.*** We intend to continue to allocate capital in a disciplined manner to projects that will produce predictable and attractive rates of return and positive Levered Free Cash Flow. We plan to direct capital to our oil-rich and low-geologic risk development opportunities, primarily in California, while focusing on leveraging capital efficiencies across our asset base with the primary objective of internally funding our capital budget and growth plan. We may also use our capital flexibility to pursue value-enhancing, bolt-on acquisitions to opportunistically improve our positions in existing basins.

- ***Proactively and collaboratively engage in matters related to regulation, the environment and community relations.*** We seek to continue to work closely with regulators and legislators throughout the rule making process to minimize adverse impacts that new legislation and regulations might have on our ability to maximize our resources and to mitigate adverse impacts to our permitting process. Additionally, we have found that constructive dialogue with regulatory representatives can help avert compliance and permitting issues. We believe that running our operations in a manner that protects the safety and health of the environment and all those that may be impacted by our operations and is in compliance with existing laws and regulations is not only the right way to run our business, but it helps us build and maintain credibility with the relevant agencies governing our operations, as well as positive relationships with the communities in which we operate. With ultimate oversight by our Board of Directors, Environmental, Health & Safety ("EH&S") considerations are an integral part of our day-to-day operations and are incorporated into the strategic decision-making process across our business.

- ***Maximize ultimate hydrocarbon recovery from our assets by optimizing drilling, completion and production techniques and investigating deeper reservoirs and areas beyond our known productive areas.*** While we continue to utilize proven techniques and technologies, we will also continuously seek efficiencies in our drilling, completion and production techniques in order to optimize ultimate resource recoveries, rates of return and cash flows. We will continue to advance and use innovative oil recovery and other recovery techniques to unlock additional value and will allocate capital towards these next generation technologies where applicable. 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.

- ***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 also seek to protect our operating expenses through fixed-price gas purchase agreements, hedging contracts and 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 protected a significant portion of our cash flows in 2021, and have sought to protect a significant portion of our anticipated cash flows in 2022, as well as a portion in 2023 through 2024, using our commodity hedging program. 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. In addition, we also hedge to meet the hedging requirements of the 2021 RBL Facility. We review our hedging program continuously as market conditions change and make our hedging decisions using a wide range of market data and analysis.

- ***Contribute to the energy transition.*** We believe that oil and gas will remain an important part of the energy landscape going forward. We recognize the oil and gas industry's role in the energy transition and we are determined to be part of the solution. This is the new energy reality. We have newly acquired capabilities to support the State of California's orphaned wells and fugitive emissions initiatives. With the fourth quarter 2021 acquisition of CJWS, we can reduce state-wide fugitive emissions, which are primarily methane, the most damaging of the greenhouse gases, by plugging and abandoning orphan and idle wells today. Additionally, we are continuing to hone our medium and long-term environmental priorities as it relates to ESG, including solar and water recycling projects and we are evaluating our acreage for carbon capture, use and storage opportunities.

Our Capital Program

For the years ended December 31, 2021 and 2020 our total capital expenditures were approximately $133 million and $76 million, respectively, on an accrual basis including capitalized overhead and interest and excluding acquisitions and asset retirement spending. Approximately 79% and 12% of capital expenditures for the year ended December 31, 2021 was directed to California oil and Utah operations, respectively. We increased our 2021 capital program compared to 2020, in response to the improved oil price environment and the improving global and national economic environment.

Our 2021 capital program was heavily weighted in the middle of the year and resulted in increases in our average daily production each quarter throughout 2021. As a result of capital deployed, production in the last quarter of 2021 was 5% higher than the last quarter of 2020. This is indicative of the positive response we get from our assets with strategic capital deployment. The year-over-year production results were impacted by the significant capital reduction in 2020 and measured ramp up in activity in early 2021. We drilled 191 wells in 2021, of which 181 were in California and consisted of 107 producing wells, 38 horizontal wells, 23 cyclic and other injectors wells and 13 delineation wells. We also drilled 10 wells in Utah.

Our 2022 capital expenditure budget for D&P operations and corporate activities is approximately $125 to $135 million, excluding approximately $8 million for C&J Well Services, which we expect will keep our annual production flat. We currently anticipate oil production will be approximately 92% of total production volume in 2022, compared to 88% in 2021 and 88% in 2020, with the change largely due to the Piceance natural gas properties divestiture in January 2022. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2022 capital development programs from cash flow from operations. The execution of these plans requires that we timely obtain certain regulatory permits and approvals, which we may not be able to obtain on a timely basis or at all. 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.

In 2021 we began to spend capital on environmental projects related to our sustainability or "ESG" initiatives. We plan to increase capital spent on these ESG projects in 2022, which will include solar generation to power operations and equipment efficiency improvements that will decrease our carbon emissions.

We currently expect to employ two to three drilling rigs in California during 2022. Additionally, we currently expect to drill approximately 120 to 130 development wells and 5 to 10 delineation wells during 2022. Of the development capital in 2022 we anticipate approximately 80-85% in California and 15-20% in Utah.

Exclusive of the capital expenditures noted above, for the full year 2021, we spent approximately $19 million on plugging and abandonment activities, exceeding our annual obligation requirements under the California idle well management plan. In 2022, we currently expect to spend approximately $21 million to $24 million for such activities and we again plan to stay ahead of 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 - Development and Production

Our predominant development and production operating area is in California, and we also have operations in Utah. In January 2022 we divested our Colorado operating area.

California

California is and has been one of the most productive oil and natural gas regions in the world. According to the U.S. Energy Information Administration as of 2015, 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 our areas of operation within the San Joaquin basin, which also include the McKittrick and Poso Creek fields. We also believe that our California focus and strong balance sheet 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 occur 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 14,000 net acres in the San Joaquin basin in Kern County, of which 91% is held by production and fee interest. Approximately 13% of our California acres are on Federal lands administered by the Bureau of Land Management ("BLM"), of which 100% is held by production. We have a 97% average working interest in our California assets, and our producing areas include:

- West California operations consist of: (i) our North Midway-Sunset sandstone properties, where we use cyclic and continuous steam injection to develop these known reservoirs; (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 and our McKittrick Field property, which is a newer steamflood development with potential for infill and extension drilling. Also located here is our North Midway-Sunset thermal diatomite properties, which requires high pressure cyclic steam techniques to unlock the significant value we believe is there and maximize recoveries. Following the November 2019 moratorium on approval of new high–pressure cyclic steam wells pending a study co-led by Lawrence Livermore National Laboratory and CalGEM of the practice to address surface expressions experienced by certain operators, we have not included these properties in our plans through 2023. Please see "—Regulation of Health, Safety and Environmental Matters—Additional CalGEM Actions on Oil and Gas Activities" for more information.

- East California operations consist of our Poso Creek property, which is an active mature shallow, heavy oil asset that we continue to develop across the property. We develop these sandstone properties with a combination of cyclic and continuous steam injections, similar to many of our west California operations.

Our California proved reserves represented approximately 81% of our total proved reserves at December 31, 2021. California accounted for 22.0 mboe/d, or 80%, of our average daily production for the year ended December 31, 2021.

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 supply approximately 18% of our steam needs and approximately 65% of our field electricity needs to power our operations in California, on average generally at a discount to electricity market prices. To further help offset our costs, we currently also sell surplus power produced by two of our cogeneration facilities under power purchase agreement ("PPA") contracts with California utility companies. We also own 62 conventional steam generators to help satisfy the steam required by our operations.

In addition, we own gathering, treatment, water recycling and softening facilities, as well as storage facilities, in California that currently have excess capacity, 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.

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 and Lake Canyon areas in Utah target the Green River and Wasatch formations that produce oil and natural gas at depths ranging from 5,000 feet to 7,000 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 90,000 net acres in the Uinta basin, of which 83% is held by production. Approximately 32% of our Utah acreage is on Federal lands administered by the BLM, of which 60% is held by production and approximately 58% of our Utah acreage is on tribal lands, of which 97% is held by production.

Our Uinta basin proved reserves represented approximately 15% of our total proved reserves at December 31, 2021 and accounted for 4.2 mboe/d or 15% of our average daily production for the year ended December 31, 2021.

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 93% of the gas gathered at these facilities is produced from wells that we operate. Current throughput at the processing plant is 15-17 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 doubled from 36 mbbl/d in 2003 to 85 mbbl/d in 2020. Approximately 84% of Utah's oil production in 2020 came from the Uinta basin in Duchesne and Uintah counties.

Piceance Basin, Colorado

The Piceance basin in northwestern Colorado is a natural gas play. In January 2022 we divested our Piceance Basin assets. Our Piceance basin proved reserves represented approximately 4% of our total proved reserves at December 31, 2021 and accounted for 1.2 mboe/d, or 4%, of our average daily production for the year ended December 31, 2021.

Our Well Servicing and Abandonment Business

In late 2021, we acquired one of the largest upstream well servicing and abandonment businesses in California, which operates as C&J Well Services, LLC. C&J Well Services provides wellsite services in California to oil and natural gas production companies, with a focus on well servicing, well abandonment services, and water logistics with a constant focus on maintaining the highest reliability standards and safety record. Our services include rig-based and coiled tubing-based well maintenance and workover services, recompletion services, fluid management services, fishing and rental services, and other ancillary oilfield services. Additionally, we perform plugging and abandonment services on wells at the end of their productive life, which creates a strategic growth opportunity for Berry. C&J Well Services 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 Well Services is critical to advancing our strategy to work with the State of California to reduce fugitive emissions - including methane and carbon dioxide - from idle wells. We believe that C&J Well Services is uniquely positioned to capture both state and federal funds to help remediate orphan idle wells (an idle well that has been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well), and there are approximately 35,000 idle wells estimated to be in California according to third-party sources.

Through C&J Well Services we operate a fleet of 73 well servicing rigs, also commonly referred to as a workover rig, 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, or repairing casings required by the operation into and out of the well, or removing equipment from the well bore; 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 276 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 1,630 pieces of rental equipment on our water logistics side.

Our Assets and Production Information

For the year ended December 31, 2021, we had average net production of approximately 27.4 mboe/d, of which approximately 88% was oil and approximately 80% was in California. In California, our average production for the year ended December 31, 2021 was 22.0 mboe/d, of which 100% was oil. Our California production in 2021 includes Placerita operations contributing average daily production in of over 800 boe/d through the end of October 2021 when those assets were divested. Additionally, we divested all of our properties in the Piceance basin of Colorado in January 2022, which had production of 1.2 mboe/d in 2021.

The table below summarizes our average net daily production for the years ended December 31, 2021 and 2020:

	Average Net Daily Production[1] for the Year Ended December 31,			
	2021		2020	
	(mboe/d)	Oil (%)	(mboe/d)	Oil (%)
California[2]	22.0	100 %	22.9	100 %
Utah	4.2	51 %	4.3	50 %
	26.2	88 %	27.2	88 %
Colorado[3]	1.2	2 %	1.3	2 %
Total	27.4	88 %	28.5	88 %

(1) Production represents volumes sold during the period.

(2) Includes production for Placerita properties though the end of October 2021 when they were divested. These properties had average daily production in 2021 of over 800 boe/d prior to the sale.

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

Production Data

The following table sets forth information regarding production for the years ended December 31, 2021 and 2020.

	Year Ended December 31,	
	2021	2020
erage daily production[1]:		
Oil (mbbl/d)	24.2	25.0
Natural gas (mmcf/d)	17.1	18.5
NGLs (mbbl/d)	0.4	0.4
Total (mboe/d)[2]	27.4	28.5

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mcf, respectively.

Our Development Inventory

We have an extensive inventory of low-geologic risk, high-return development opportunities. As of December 31, 2021, we identified 10,414 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 operate approximately 98% 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, 2021, the combined net acreage covered by leases expiring in the next three years represented approximately 11% of our total net acreage, of which 91% 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.

The following table summarizes certain information concerning our active producing and identified development assets as of December 31, 2021:

	Acreage		Net Acreage Held By Production and Fee Interest(%)	Producing Wells, Gross[3][4]	Average Working Interest (%)[4][5]	Net Revenue Interest (%)[4][6]	Identified Drilling Locations[7]	
	Gross	Net[1][2]					Gross	Net
California	18,823	14,111	91 %	2,448	97 %	94 %	9,981	9,942
Utah	107,069	90,108	83 %	970	95 %	79 %	433	369
Colorado	9,259	6,780	100 %	169	72 %	62 %	—	—
Total	135,151	110,999	85 %	3,587	95 %	90 %	10,414	10,311

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

(2) Of which approximately 13% are BLM acres in California and 32% are BLM acres in Utah.

(3) Includes 483 steamflood and waterflood injection wells in California.

(4) Excludes 90 wells in the Piceance basin each with a 5% working interest. We divested all of our Colorado Piceance basin assets in January 2022.

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

(6) Represents our weighted-average net revenue interest for the year ended December 31, 2021.

(7) Our total identified drilling locations include approximately 719 gross (715 net) locations associated with PUDs as of December 31, 2021, including 90 gross (90 net) steamflood 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, 2021, we had estimated total proved reserves of 97 mmboe, an increase from 95 mmboe, as of December 31, 2020. Our overall proved reserves increased 12 mmboe, or 13%, before production of 10 mmboe, the majority of which is due to price revisions. We replaced 120% of our production with additional proved reserves. Based on current Brent strip pricing we would expect a further improvement in the 2022 proved reserves.

The majority of our reserves are composed of crude oil in shallow, long-lived reservoirs. As of December 31, 2021, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately $1.2 billion and $1.5 billion, respectively. These values represent significant increases from the prior year end of $516 million and $520 million. 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, 2021, approximately 81% of our proved reserves and approximately 91% of the PV-10 value of our proved reserves are derived from our assets in California. We also have approximately 15% of our proved reserves and approximately 8% of the PV-10 value in the Uinta basin in Utah, a mature, light-oil-prone play with significant undeveloped resources. Approximately 4% of our proved reserves and only 1% of the related PV-10 value at December 31, 2021 were located in the Piceance basin in Colorado. These Colorado properties consisted entirely of natural gas and we divested these properties in January 2022.

The tables below summarize our estimated proved reserves and related PV-10 by category as of December 31, 2021:

	Proved Reserves as of December 31, 2021(1)(5)							
	Oil (mmbbl)	Natural Gas (bcf)	NGLs (mmbbl)	Total (mmboe)(2)	% of Proved	% Proved Developed	Capex(3) ($MM)	PV-10(4) ($MM)
PDP	47	60	1	58	60 %	90 %	14	911
PDNP	6	—	—	6	6 %	10 %	17	128
PUD	33	2	—	33	34 %	— %	451	474
Berry total proved reserves	86	62	1	97	100 %	100 %	482	1,513
California total proved reserves	79	—	—	79			455	1,374

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(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 $69.47 per bbl Brent for oil and natural gas liquids ("NGLs") and $3.64 per mmbtu Henry Hub for natural gas at December 31, 2021. The volume-weighted average prices over the lives of the properties were estimated at $65.10 per bbl of oil and condensate, $36.08 per bbl of NGLs and $3.98 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, 2021.

(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.

(5) In January 2022 we divested our Piceance basin properties in Colorado.

The following table summarizes our estimated proved reserves and related PV-10 by area as of December 31, 2021. 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. We divested the Colorado properties in the Piceance basin in January 2022.

	Proved Reserves as of December 31, 2021[1]			
	California (San Joaquin basin)	**Utah (Uinta basin)**	**Colorado (Piceance basin)[5]**	**Total**
Proved developed reserves:				
Oil (mmbbl)	47	6	—	53
Natural Gas (bcf)	—	35	25	60
NGLs (mmbbl)	—	1	—	1
Total (mmboe)[2][3]	47	13	4	64
Proved undeveloped reserves:				
Oil (mmbbl)	32	1	—	33
Natural Gas (bcf)	—	2	—	2
NGLs (mmbbl)	—	—	—	—
Total (mmboe)[3]	32	1	—	33
Total proved reserves:				
Oil (mmbbl)	79	7	—	86
Natural Gas (bcf)	—	37	25	62
NGLs (mmbbl)	—	1	—	1
Total (mmboe)[3]	79	14	4	97
PV-10 ($million)[4]	$ 1,374	$ 124	$ 15	$ 1,513

(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 $69.47 per bbl Brent for oil and NGLs and $3.64 per mmbtu Henry Hub for natural gas at December 31, 2021. The volume-weighted average prices over the lives of the properties were $65.10 per bbl of oil and condensate, $36.08 per bbl of NGLs and $3.98 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**—**Oil, natural gas and NGL prices are volatile and directly affect our results.**"

(2) For proved developed reserves approximately 10% of total and 11% 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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mcf, respectively.

(4) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "—PV-10." PV-10 does not give effect to derivatives transactions.

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

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, 2021:

		At December 31, 2021
		(in millions)
California PV-10	$	1,374
Utah PV-10		124
Colorado PV-10		15
Total Company PV-10		1,513
Less: present value of future income taxes discounted at 10%		(280)
Standardized measure of discounted future net cash flows	$	1,233

Proved Reserves Additions

Our overall proved reserves increased 12 mmboe, or 13%, before production. A majority of this increase was a result of the higher price environment and extensions. We replaced 120% of our production with additional proved reserves. The total changes to our proved reserves from December 31, 2020 to December 31, 2021 were as follows:

	California (San Joaquin basin)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
		(in mmboe)[1]		
Beginning balance as of December 31, 2020	87	7	1	95
Extensions and discoveries	1	2	—	3
Revisions of previous estimates	(1)	7	3	9
Purchases of minerals in place[2]	—	—	—	—
Sales of minerals in place[3]	—	—	—	—
Current year production	(8)	(2)	—	(10)
Ending balance as of December 31, 2021	79	14	4	97

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mcf, respectively.

(2) Purchases of minerals in place were less than 1 mmboe.

(3) Sales of minerals in place were less than 1 mmboe.

Extensions. During 2021, we added 3 mmboe of proved reserves from extensions in our California and Utah properties.

Revisions of Previous Estimates.

Revisions related to price - Product price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations because the extra margin extends their expected life and renders more projects economic. Conversely, when prices drop, we experience the opposite effects. In 2021, our total net positive price revision was 9 mmboe in California, 6 mmboe in Utah, and 3 mmboe in Colorado.

Revisions related to performance - Performance-related 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 2021, we had negative technical revisions of 10 mmboe in California, which was partially offset by positive technical revisions of 1 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.

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 decreased 7 mmboe in 2021 largely due to reclassifications to proved developed reserves. Our development program in 2021 was focused on maintaining production with minimal capital spent on growth limiting the proved undeveloped reserves additions. The total changes to our proved undeveloped reserves from December 31, 2020 to December 31, 2021 were as follows:

	California (San Joaquin and Ventura basins)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
	(in mmboe)[(1)]			
Beginning balance as of December 31, 2020	39	—	—	39
Extensions and discoveries	1	1	—	2
Revisions of previous estimates	(3)	—	—	(3)
Reclassifications to proved developed	(5)	—	—	(5)
Ending balance as of December 31, 2021	32	1	—	33

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(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mcf, respectively.

Extensions. During 2021, we added 2 mmboe of proved undeveloped reserves from extensions based on drilling results from unproven locations in Midway Sunset, McKittrick, and Utah.

Revisions of previous estimates.

Revisions related to price - In 2021, our net positive price revision on proved undeveloped reserves were approximately 1 mmboe in California, which was the result of higher prices due to the current commodity price environment.

Revisions related to performance - In 2021, our net negative performance-related revision on proved undeveloped reserves was 4 mmboe in California which resulted primarily from our thermal Diatomite and Hill Tulare areas.

Reclassifications to proved developed. During 2021, we transferred approximately 5 mmboe of proved undeveloped reserves to the proved developed category due to development drilling activity in 2021. Our development of proved undeveloped reserves during much of 2020 and 2021 was significantly limited by the severe downturn in the industry, which impacted not only our capital over those two years but also our strategic development approach. With our 2021 development program, we converted 4.5 mbbls of our beginning-of-the year inventory of proved undeveloped reserves, spending approximately $48 million of capital. We expect to have sufficient future capital to develop our proved undeveloped reserves at December 31, 2021 within five years. Prices substantially below current levels for a prolonged period of time may require us 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 proved undeveloped reserves are determined in accordance with SEC guidelines for development within five years. We believe we have management's commitment and sufficient future capital to develop all of our proved undeveloped reserves.

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. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability and include production and well test data, downhole completion information, geologic data, 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 Executive Vice President of Business Development, who has a Masters in Geology from the University of South Carolina and a Bachelors in Geology from Carleton College, and more than 35 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 Registered 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 lower than estimated.***”

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2021, we have approximately 719 gross (715 net) drilling locations attributable to our proved undeveloped reserves, compared to 808 gross (805 net) as of December 31, 2020. The decrease in drilling locations attributable to our proved undeveloped reserves is primarily due to the 2021 drilling activity. 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.

Unproven Drilling Locations

We have also identified a multi-year inventory of 9,695 gross (9,596 net) unproven drilling locations as of December 31, 2021, compared to 9,565 gross (9,533 net) unproven drilling locations as of December 31, 2020. 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.***”

The table below sets forth our proved undeveloped drilling locations and unproven drilling locations as of December 31, 2021.

	PUD Drilling Locations (Gross)		Unproven Drilling Locations (Gross)		Total Drilling Locations (Gross)	
	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells
California	611	90	7,328	1,952	7,939	2,042
Utah	18	—	415	—	433	—
Colorado(1)	—	—	—	—	—	—
Total Identified Drilling Locations	629	90	7,743	1,952	8,372	2,042

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

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,		
	2021	2020	2019
SJV Midway Sunset			
Total production(1):			
Oil (mbbls)	5,666	5,933	5,543
Natural gas (bcf)	—	—	—
NGLs (mbbls)	—	—	—
Total (mboe)(2)	5,666	5,933	5,543

	Year Ended December 31,		
	2021	2020	2019
SJV Belridge Hill			
Total production(1):			
Oil (mbbls)	1,505	1,280	1,312
Natural gas (bcf)	—	—	—
NGLs (mbbls)	—	—	—
Total (mboe)(2)	1,505	1,280	1,312

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mcf, respectively.

Productive Wells

As of December 31, 2021, we had a total of 3,587 gross (3,417 net) productive wells (including 483 gross and net steamflood and waterflood injection wells), approximately 95% 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 and wells in our Piceance basin are primarily gas and also produce condensates. We were participating in 16 steamflood projects and one waterflood project located in the San Joaquin basin, and one waterflood project located in the Uinta basin.

The following table sets forth our productive oil and natural gas wells (both producing and capable of producing) as of December 31, 2021.

	California (San Joaquin basin)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
Oil				
Gross[(1)]	2,448	970	—	3,418
Net[(2)]	2,374	922	—	3,296
Gas				
Gross[(1)(3)]	—	—	169	169
Net[(2)(3)]	—	—	121	121

(1) The total number of wells in which interests are owned. Includes 483 steamflood and waterflood injection wells in California.
(2) The sum of fractional interests.
(3) Excludes 90 wells in the Piceance basin each with a 5% working interest.

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, 2021.

	California (San Joaquin basin)	Utah and Other (Uinta and Piceance basins)	Total
Developed[(1)]			
Gross[(2)]	7,078	47,863	54,941
Net[(3)]	7,053	43,346	50,399
Undeveloped[(4)]			
Gross[(2)]	11,746	68,465	80,211
Net[(3)]	7,059	53,542	60,601

(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, 2021, we were not participating in any uncompleted wells.

Drilling Activity

The following table shows the net development wells we drilled during the periods indicated. 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. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	California (San Joaquin and Ventura basins[3])	Utah (Uinta basin)	Colorado (Piceance basin)	Total
2021				
Oil[1]	181	10	—	191
Natural Gas	—	—	—	—
Dry	—	—	—	—
2020				
Oil[1]	45	—	—	45
Natural Gas	—	—	—	—
Dry	—	—	—	—
2019				
Oil[1][2]	335	3	—	338
Natural Gas	—	—	—	—
Dry	—	—	—	—

(1) Includes injector wells.

(2) Includes 50 wells that had not yet been connected to gathering systems in California.

(3) Effective October 2021, we completed the sale of our Placerita Field property in the Ventura Basin in Los Angeles County, California, which included 1 well in 2019, 1 well in 2020 and zero wells in 2021.

Delivery Commitments

We have contractual agreements to provide gas volumes for processing, some of which specify fixed and determinable quantities and all of which were in Utah. As of December 31, 2021, the volumes contracted to be processed were approximately 4,560 mcf/d through February 2023. We have significantly more production than the amounts committed for delivery and have the ability to secure additional volumes of products as needed.

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 95% working interest for operated wells and 98% operating control in our properties.

Our California operations are primarily focused on the thermal Sandstones, 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	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 heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We have cyclic and continuous steam injection projects in the San Joaquin basin, primarily 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. Historically, we start production from heavy oil reservoirs with cyclic injection and then expand operations to include continuous injection in adjacent wells. 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 shallower in depth (600 to 2,500 ft) than our other programs and the wells are relatively inexpensive to drill and complete at approximately $400,000 per well. Therefore, we can normally implement a drilling program quickly with attractive rates of return.

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 please see “—Electricity.” 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 62 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 California price indexes, and in some cases includes transportation charges.

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 65% to 70% 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. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low transportation costs, coupled with Brent-influenced pricing, will allow us to continue to realize 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 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 enter into hedges for gas purchases to protect our operating expenses from price fluctuations. We also 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.

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 and 21Z cogeneration facilities are used solely for field operations.

For the year ended December 31, 2021, excluding the Placerita cogeneration facility which we divested in October 2021, we sold approximately 383,000 megawatt-hours ("MWhs") per day of cogen power into the grid and on average consumed approximately 291 MWhs per day of cogen power for lease operations. The four cogeneration facilities produced an average of approximately 25,000 barrels of steam per day. 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 two of our cogeneration facilities under long-term PPAs approved by the California Public Utilities Commission (the "CPUC") to two California investor-owned utilities, Southern California Edison Company ("Edison") and Pacific Gas and Electric ("PG&E"). These PPAs expire in various years between 2022 and 2026.

Principal Customers

For the year ended December 31, 2021, sales to Tesoro Refining and Marketing, PBF Holding, Kern Oil & Refining, and Phillips 66 accounted for approximately 30%, 16%, 14%, and 12% respectively, of our sales. At December 31, 2021, trade accounts receivable from three customers represented approximately 28%, 13% and 11% 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, 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 development and production 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 the availability of 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. Our revenues and earnings can be affected by several factors, including changes in competition, fluctuations in drilling and completion activity, 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 can impact our drilling, production and well servicing activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling and completion objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may have been and in the future may be impacted by ice and snow in the winter, especially in Utah, and by electrical storms and high temperatures in the spring and summer, as well as by wild fires and rain.

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

Regulatory Matters

Regulation of the Oil and Gas Industry

Like other companies in the oil and gas industry, our operations are subject to a wide range of complex federal, state and local laws and regulations. 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 exploration, development and production in California, 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 potentially 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, and reduce the amount of oil and natural gas that we can produce from our wells below levels that would otherwise be possible. Additionally, the regulatory burden on the industry increases our costs and consequently may have an adverse effect upon operations, capital expenditures, earnings and our competitive position. 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 future prospects.

The California Department of Conservation’s Geologic Energy Management Division (“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 State Lands Commission’s administration of state surface and mineral interests, as well as other state and local agencies. The Bureau of Land Management (“BLM”) of the U.S. Department of the Interior 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 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 may result in delays in the issuance of such permits and approvals and the imposition of 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 habitat, 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, typically through either an environmental review or an exemption by a state or local agency.

In Kern County, where all of our California assets are now located, we historically have satisfied CEQA by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report ("Kern County EIR") covering oil and gas operations in Kern County which was certified by the Kern County Board of Supervisors in 2015. In addition to CalGEM, other state agencies have relied on the Kern County EIR to satisfy the CEQA requirements in connection with permitting and project approval decisions for oil and gas projects in unincorporated Kern County. In 2020, a group of plaintiffs challenged the Kern County EIR, and subsequently the California Fifth District Court of Appeals issued a ruling invalidating a portion of the Kern County EIR until Kern County made certain revisions to the Kern County EIR and recertified it ("Kern County Ruling"). To address the Kern County Ruling, Kern County elected to prepare a supplemental EIR which was approved by the Kern County Board of Supervisors in March 2021. Following further challenges by plaintiffs in March 2021, a Kern County Superior Court judge suspended use of the supplemental EIR, stopping the issuance of new oil and gas permits by Kern County (the "Kern County Permit Suspension") in October 2021, pending judicial review of the supplemental EIR and a determination of its compliance with CEQA requirements by the Kern County Superior Court. A hearing on the matter by the Kern County Superior Court is scheduled for April 2022. We cannot predict the outcome of this hearing on the Kern County EIR or whether it will result in the imposition of more onerous permit requirements or other requirements or restrictions on land use and exploration and production activities.

Importantly, the Kern County Ruling and the Kern County Permit Suspension did not invalidate existing permits and our plans and operations have not been materially impacted to date. Until Kern County is able to resolve the challenges regarding the sufficiency of the Kern County EIR and resume the ability to issue permits, our ability to obtain new permits and approvals to enable our future plans in Kern County requires demonstrating to CalGEM compliance with CEQA. Demonstrating compliance with CEQA without being able to reference the Kern County EIR is a more technically, time and cost intensive process and may, among other things, require that we conduct an environmental impact review. As a result, we together with other Kern County operators have experienced delays in the issuance of permits by CalGEM, as well as a more time- and cost- intensive permitting process. Approximately 10% of our current 2022 production plans is expected to come from the drilling of new wells, which requires the issuance of new permits, and the workover of existing wells; our existing producing wells are expected to contribute the other 90%. We believe that we have sufficient permit inventory to cover our drilling plans through the first quarter of 2022. However, our drilling plans for the remainder of the year, and therefore our current 2022 production goals, may be impacted by our ability to timely obtain the required permits and approvals to support those planned activities, particularly if the Kern County Permit Suspension continues or if there are further delays in or new restrictions imposed upon the issuance or renewal of permits and approvals required for oil and gas activities in Kern County. If we are unable to obtain the permits required to support our current 2022 drilling plans, we may reduce our planned capital expenditures or deploy that capital to other activities. Additionally, any postponement or elimination of our development drilling program could result in a reduction of proved reserves volumes and materially affect our business, financial condition and results of operations. In the future, if we are unable to obtain the required permits and approvals needed to conduct our operations, including our development drilling program, on a timely basis or at all our business, financial condition and results of operations could be adversely impacted.

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. The lawsuit is ongoing and we cannot predict its ultimate outcome or whether it could result in changes to the requirements for demonstrating compliance with CEQA and permitting process, even if the Kern County EIR is ultimately deemed sufficient and reinstated.

California Underground Injection Control Regulations

The federal Safe Drinking Water Act ("SDWA") and the 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 EPA directly administers the UIC program 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 U.S. Environmental Protection Agency ("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 the State'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 EPA, amongst other measures. The State responded in October 2021 with a proposed compliance plan but, to date, EPA has not yet responded. Additional limitations on injection well operations increased federal oversight of the UIC permitting process, or a lack of funds for the State 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 for 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 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. Changes in the process for approving infill wells has the potential to delay permitting injection and other activities, or otherwise result in increased compliance costs on our operations. Our 2022 plans, as well as potentially our future plans, 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 can be no guarantee that we continue to successfully manage these issues in the future.

California Idle Well Regulations

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 been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well. In April 2019, CalgGEM 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 plugging idle wells that will not return to service, 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 AB 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 emissions while meeting the state's energy needs.

We have submitted an idle well management plan and are fulfilling the conditions of that plan to meet our obligations. In 2021, we spent approximately $19 million on plugging and abandonment activities, exceeding our annual obligation requirements under our idle well management plan. In 2022 we expect to spend approximately $21 million to $24 million for such activities and we again plan to stay ahead of our annual plugging and abandonment obligations in keeping with our commitments to be a responsible operator.

Additionally, in the fourth quarter of 2021, we acquired C&J Well Services, a profitable new business line, to provide standard well services to the industry in California and to accelerate the reduction of fugitive emissions by plugging and abandoning idle wells across California for ourselves and other operators, as well as the State of California. We believe that C&J Well Services is uniquely positioned to capture both state and federal funds to help remediate orphan idle wells (an idle well that has been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well), and there are approximately 35,000 idle wells estimated to be in California according to third-party sources.

Additional Actions Impacting Oil and Gas Activities in California

In September 2020, the California Governor 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 greenhouse gases, 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 (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). 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. In response to the executive order, in October 2021, CalGEM released for public comment a "discussion draft" proposed regulation that would prohibit new wells and facilities within a 3,200-foot setback area from homes, schools, hospitals, nursing homes, and other sensitive locations. The proposed regulation would also require pollution controls for existing wells and facilities within the same 3,200-foot setback area. CalGEM is currently in the process of conducting an economic analysis of the proposed rule. Following this analysis, CalGEM will submit a proposed rule to the Office of Administrative Law and will begin an additional process of receiving formal comments and refinement of the proposal as needed before a final rule can be issued. We continue to assess the impacts of this rule, and we currently anticipate that approximately 29% of our acreage could be impacted by the setback requirements if finalized as proposed.

Separately, in October 2020, the Governor 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.

Restrictions on Oil and Gas Developments on Federal Lands

As of December 31, 2021, approximately 13% and 32% of our net acreage in California and Utah, respectively, is on federal land, which comprises approximately 14% and 22% of our total proved reserves in California and Utah, respectively, and approximately 19% and 28% of our PUD locations in California and Utah, respectively. The potential exists for additional federal restrictions on oil and gas activities on federal lands 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, effectively halting implementation of the leasing suspension. The federal government is appealing the district court decision, but the BLM has scheduled a lease sale to occur in the first quarter of 2022. 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 by adjusting royalty and bonding rates, prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. Implementation of many of the recommendations in the DOI report will require Congressional action and we cannot predict to the extent to which the recommendations may be implemented now or in the future, but restrictions on federal oil and gas activities could result in increased costs and adversely impact our operations.

Operations on Tribal Lands

As of December 31, 2021, approximately 74% of our net acreage in Utah is on tribal lands, which comprises approximately 74% of our total proved reserves in Utah, and approximately 72% 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. Our undeveloped thermal diatomite assets currently are not part of our near-term development plans, nor are any areas in California that would require well stimulation treatments ("WST") (also known as hydraulic stimulation, hydraulic fracturing or fracking). We do rely on other methods of well stimulation and injection, including the use of cyclic and continuous steam injection, which is heavily regulated. Any restrictions on the use of those well stimulation treatments or other forms of injection 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 recent regulatory actions like 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 three 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’s intent to seek legislation to end the issuance of new hydraulic fracturing permits by 2024; the executive order is 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. Only our undeveloped thermal diatomite assets require new high-pressure cyclic steam wells and those assets are currently not in our near-term development plans. Our 2022 plans do not include new high-pressure cyclic steam wells, nor did our 2020 and 2021 plans. Additionally, we have not been impacted by the hydraulic fracking announcement as our current plans do not require the development of assets requiring hydraulic fracturing in California.

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. In 2015, the BLM issued regulations regarding the public disclosure of chemicals used in stimulation treatments, well construction and integrity and management of waste fluids resulting from hydraulic fracturing activities on federal and tribal lands. While the BLM rescinded these regulations in 2017, the rescission is subject to ongoing legal challenge. Additionally, the regulations may be reconsidered under the Biden Administration. If the rule is reinstated, or a similar rule is promulgated, the outcome could materially impact our operations in the Uinta basin, where as of December 31, 2021, approximately 22% of our proved reserves in Utah were located on federal lands and approximately 74% 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 due to delays in operations at well sites and also 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, 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.

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 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 Heath 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 safety of oil and natural gas pipelines, including, with some specific exceptions, oil and natural gas gathering lines;
- 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);
- U.S. Department of Interior regulations, which regulate oil and gas production activities on federal lands and impose 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, 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 greenhouse gas ("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;

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, 2021, 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 2022 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 development and production 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 U.S. Environmental Protection Agency ("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 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. 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 September 2018, California adopted a law committing California, the fifth largest economy in the world, to the use of 100% zero-carbon electricity by 2045, and the Governor of California also signed an executive order committing California to total economy-wide carbon neutrality by 2045. Additionally, Governor Newsom requested that the CARB analyze pathways to phase out oil extraction across the state by no later than 2045. 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 a 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 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; for more information, see our regulatory disclosure titled “Air Emissions”. 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, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Subsequently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. 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, the Securities and Exchange Commission announced its intention to promulgate rules requiring climate disclosures. Although the form and substance of these requirements is not yet known, this may result in additional costs to comply with any such disclosure requirements.

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, enhanced production techniques and fluid injection or disposal, that 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 exploration and production activities, and reduce demand for the oil and natural gas we produce."***

Human Capital Resources

As of December 31, 2021, we had 1,224 employees, all of whom are located in the United States. Of those, 889 employees joined our organization in the fourth quarter of 2021 with the acquisition of CJWS. Currently, none of our employees are covered under collective bargaining or union agreements. We also utilize the service of many 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 has oversight responsibilities for the Company's human capital management policies, processes and practices, including those related to workforce diversity, pay equity and 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 provide development opportunities and financial rewards so that our employees are engaged and focused on providing safe, affordable, 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 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 make sure all employees are fully engaged and empowered to achieve their potential and we are committed to attracting, developing and retaining a highly qualified, diverse and value-focused work force. Our engagement approach centers on transparency and accountability and we use a variety of channels 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.

We 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 unlawful 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 a person's race, color, ethnicity, national origin, ancestry, citizenship status, sex, gender identity and/or expression, sexual orientation, mental disability, physical disability, medical condition, neuro(a)typicality, physical appearance, genetic information, age, parental status or pregnancy, marital status, religion, creed, political affiliation, military or veteran status, socioeconomic status or background, and any other characteristic protected by law.

Berry is similarly dedicated to this policy with respect to recruitment, hiring, placement, promotion, transfer, training, compensation, benefits, employee activities and general treatment during employment. Our goal is to reflect the broad spectrum of cultural, demographic, and philosophical differences of the communities where we operate, and foster a culture that supports and protects diversity. As a result of our efforts, we have attracted and retained highly talented and experienced women to our workforce in positions across our organization. Currently, our Board is approximately 33% women, our executive team is 17% women, our senior management team is 30% women, and our total workforce is approximately 18% women, which we believe is higher than the U.S. industry average based on available data.

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, management and all employees. Meeting meaningful EH&S organizational metrics, including with respect to health and safety and spill prevention, is a part of our incentive programs for our entire workforce.

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. We make such filings available free of charge through our website as soon as reasonably practicable after they are filed with the SEC. 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 within the states where we operate.
- 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 our business, financial condition and results of operations may be materially and adversely affected.

- The marketability of our production is dependent upon the availability of transportation and storage facilities, most of which we do not control. If we are unable to access such facilities on commercially reasonable terms or at all, our access to markets for the commodities we produce could be restricted, which would likely cause interruption to operations, curtailment of production, and reduced revenues, among other adverse consequences.
- 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 lower than estimated.
- Unless we replace oil and natural gas reserves, our future reserves and production will decline.
- The drilling and production of oil and natural gas involves many uncertainties, some of which we do not control, that could adversely affect our results.
- 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, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.
- 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.
- 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.
- Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this highly regulated geographic area.
- 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 not be insured for, or our insurance may be inadequate to protect us against, these risks.
- 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 failures and cyberattacks could affect us significantly.
- Increasing attention to environmental, social and governance (“ESG”) matters 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. We may be unable to fund these investments through operating cash flow or obtain additional capital on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves or production.
- Inflation could adversely impact our ability to control our costs, including our operating expenses and capital costs.
- Our hedging activities, including those required by our 2021 RBL facility, limit our ability to realize the full benefits of increases in commodity prices. 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.
- 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 RBL Facility is subject to periodic redeterminations and our lenders could reduce capital available to us for investment.

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

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 including the permitting approval process for oil and gas activities that could increase costs, restrict operations, and delay our implementation of, or cause us to change, our business strategy and plans.
- 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 exploration and production activities, and reduce demand for the oil and natural gas we produce.

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 an “emerging growth company,” and are able to take advantage of reduced disclosure requirements applicable to “emerging growth companies,” which could make our common stock less attractive to investors.
- Our internal control over financial reporting is not currently required to meet all of the standards of Section 404 of the Sarbanes-Oxley Act, but failure to achieve and maintain effective internal control over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act standards could adversely affect 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 that some stockholders may consider beneficial.
- 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.
- Changes in the method of determining London Interbank Offered Rate (“LIBOR”), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

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.

Our oil and gas operations in California are subject to compliance with the California Environmental Quality Act (CEQA), and we cannot receive certain permits and other approval for our operations until a demonstration of compliance with CEQA has been made. There have been a number of developments at both the California state and local level that have resulted in delays in the issuance of permits for oil and gas activities in Kern County, as well as a more time- and cost- intensive permitting process. In we are unable to timely receive the permits and other approvals needed for our 2022 plans, or for our future plans, our financial condition, results of operations and prospects could be adversely and materially impacted.

In Kern County, where all of our California assets are now located, we historically have satisfied CEQA by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report ("Kern County EIR") covering oil and gas operations in Kern County which was certified by the Kern County Board of Supervisors in 2015. In addition to CalGEM, other state agencies have relied on the Kern County EIR to satisfy the CEQA requirements in connection with permitting and project approval decisions for oil and gas projects in unincorporated Kern County. However, a group of plaintiffs challenged the Kern County EIR, and subsequently the California Fifth District Court of Appeals issued a ruling invalidating a portion of the Kern County EIR until Kern County made certain revisions to the Kern County EIR and recertified it ("Kern County Ruling"). To address the Kern County Ruling, Kern County elected to prepare a supplemental EIR which was approved by the Kern County Board of Supervisors in March 2021. Following further challenges by plaintiffs in March 2021, a Kern County Superior Court judge suspended use of the supplemental EIR, stopping the issuance of new oil and gas permits by Kern County (the "Kern County Permit Suspension") in October 2021, pending judicial review of the supplemental EIR and a determination of its compliance with CEQA requirements by the Kern County Superior Court. A hearing on the matter by the Kern County Superior Court is scheduled for April 2022. We cannot predict the outcome of this hearing on the Kern County EIR as supplemented or whether it will result in the imposition of more onerous permit application requirements or other requirements or restrictions on land use and exploration and production activities.

Importantly, the Kern County Ruling and the Kern County Permit Suspension did not invalidate existing permits and our plans and operations have not been materially impacted to date. Until Kern County is able to resolve the challenges regarding the sufficiency of the Kern County EIR and resume the ability to issue permits, CalGEM is serving as lead agency for CEQA purposes and our ability to obtain new permits and approvals to enable our future plans in Kern County requires demonstrating to CalGEM an alternative way of complying with CEQA. Demonstrating compliance with CEQA independently - without being able to reference the Kern County EIR - is a more technically, time and cost intensive process and may, among other things, require that we conduct an environmental impact review. As a result, we together with other Kern County operators have experienced delays in the issuance of permits by CalGEM, as well as a more time- and cost- intensive permitting process. We believe that we currently have sufficient permit inventory to cover our drilling plan through the first quarter of 2022. However, our 2022 plans may be impacted by our ability to timely obtain the required permits and approvals to conduct planned operations through the remainder of the year, particularly if the Kern County Permit Suspension continues or if there are further delays in or new restrictions imposed upon the issuance or renewal of permits covering oil and gas activities in Kern County. 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.

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. The lawsuit is ongoing and we cannot predict its ultimate outcome or whether it could result in changes to CalGEM's requirements for compliance with CEQA, 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 future requirements for demonstrating compliance with CEQA and therefore our ability to timely obtain the permits and approvals needed to conduct our operations.

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. Federal, state and local laws and regulations govern most aspects of exploration and production in California. Collectively, the effect of the existing laws and regulations is to potentially 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, and reduce the amount of oil and natural gas that we can produce from our wells below levels that would otherwise be possible. Several bills have been introduced recently but failed to advance in the California State Legislature that restrict or prohibit the issuance or renewal of permits for various well stimulation and recovery techniques. Although these legislative efforts have failed, we cannot predict the outcome of future efforts. What's more, the regulatory burden on the industry increases our costs and consequently may have an adverse effect upon capital expenditures, earnings or competitive position. 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.

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 three 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 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 September 2020, the California Governor 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 greenhouse gases, 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. 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.

- In October 2020, the California Governor 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 October 2021, CalGEM released for public comment a "discussion draft" proposed regulation that would prohibit new wells and facilities within a 3,200-foot setback area from homes, schools, hospitals, nursing homes, and other sensitive locations. The proposed regulation would also require pollution controls for existing wells and facilities within the same 3,200-foot setback area. CalGEM is currently in the process of conducting an economic analysis of the proposed rule. Following this analysis, CalGEM will submit a proposed rule to the Office of Administrative Law and will begin an additional process of receiving formal comments and refinement of the proposal as needed before a final rule can be issued. We continue to assess the impacts of this rule, and we currently anticipate that approximately 29% of our acreage could be impacted by the setback requirements if finalized as proposed.

In February 2021, California State Senators Scott Wiener and Monique Limón introduced Senate Bill 467, which proposes to halt the issuance or renewal of permits for hydraulic fracturing, acid well stimulation treatments, cyclic steaming, and water and steam flooding starting January 1, 2022, and then prohibit these extraction methods entirely starting January 1, 2027. SB 467 also would have prohibited all new or renewed permits for oil and gas extraction within 2,500 feet of any homes, schools, healthcare facilities or long-term care institutions such as dormitories or prisons, by January 1, 2022. However, SB 467 never made it out of committee and other bills to limit well stimulation treatments have also previously been introduced and failed to pass through the California legislature. Although these legislative efforts have failed, it is possible that SB 467 or similar legislation could be reintroduced in the future and we cannot predict the results of such future efforts. While currently none of our California operations rely on hydraulic fracturing stimulation they do rely on other methods of well stimulation and injection, including cyclic steaming and water and steam flooding. Any restrictions on the use of those well stimulation treatments or other forms of injection may adversely impact our operations, including causing operational delays, increased costs, and reduced production, which could adversely affect our revenues, results of operations and net cash provided by operating activities. For additional information on regulatory and legislative risks in California that could adversely impact our operations. See "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters."

The COVID-19 pandemic and related developments in the global oil markets had material adverse consequences for general economic, business and industry conditions and impacted the Company's operations, financial condition, results of operations, cash flows and liquidity and those of its purchasers, suppliers and other counterparties.

The onset of the COVID-19 pandemic significantly affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the onset of the pandemic resulted in widespread travel restrictions, business closures and other restrictions that led to a significant reduction in demand for oil, NGL and gas, resulting in oil prices declining significantly beginning in the first quarter or 2020. In response to the reduced demand for, and prices of, crude oil, we reduced our 2020 planned capital expenditures by more than 50%, which negatively impacted production for that year.

While demand for and prices for oil, NGLs and gas generally improved during 2021 and into 2022 as travel restrictions, business closures and other restrictions were lifted, an increase in infections or the onset of a new variant of the virus could again reduce demand for and prices of oil, NGLs and gas. Persistently weak or additional declines in commodity prices could adversely affect the economics of our existing wells and planned future wells, result in additional impairment charges to existing properties, and, similar to steps we took in 2020 after the onset of the pandemic, cause us to reduce expenditures and delay or abandon planned drilling operations resulting in production declines, which could have a material adverse effect on our operations, financial condition, cash flows, and the quantity and value of estimated proved reserves that may be attributed to our properties.

Our operations also may be adversely affected if significant portions of our workforce - and that of our customers and suppliers - are unable to work effectively, because of illnesses, quarantines, government actions, or other restrictions in connection with the pandemic. Although we managed the transition to temporary work from home arrangements and subsequent office re-openings without a significant loss in business continuity, we incurred additional costs and experienced some inefficiencies during the year as a result. If the ongoing outbreak were to worsen, and additional restrictions are implemented, certain operational and other business processes could slow which may result in longer time to execute critical business functions, higher operating costs and uncertainties regarding the quality of services and supplies, any of which could adversely affect our operating results for as long as the current pandemic persists and potentially for some time after the pandemic subsides.

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. The outbreak of COVID-19 followed by certain actions taken by OPEC+ caused crude oil prices to decline significantly beginning in the first quarter of 2020, and prices remained below pre-pandemic levels for a prolonged period before they recovered. If oil prices were to significantly decline again 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:

- 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 (e.g., global health epidemics such as the recent COVID-19 pandemic);
- the actions of OPEC and/or OPEC+;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production 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, the impacts of the COVID-19 pandemic, 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 were 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. Even as Brent pricing reached a historic low during the second quarter of 2020, we also experienced an adverse widening in the price differential between Brent and the California benchmark due to the lack of local demand and storage capacity. Although market conditions and the differential improved over the latter half of 2021, California pricing remained below pre-pandemic levels for a prolonged period.

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.

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 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 lower than estimated.

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; 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 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 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*." The Company reduced its planned capital expenditures in 2020 in response to the effects of COVID-19 and the actions of OPEC+, which negatively impacted production during 2020. While we subsequently increased our planned capital expenditures for 2021, it is possible that lower-than-expected demand and prices for commodities in the future could materially and adversely affect our future planned capital expenditures. 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 the California moratorium on approval of new high-pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators, could prevent us from planned drilling activities. Additionally, as discussed under "—Risks Related to Regulatory Matters," 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 11% of our total net acreage at December 31, 2021.

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. Our capital expenditure budget for 2022 does not allocate any amounts for acquisitions of oil and natural gas properties. If we make acquisitions, we would need to use cash flows or seek additional capital, both 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 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 18% of our steam capacity and approximately 65% 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. For example, during 2021 electricity sales increased by $10 million, or 38%, due to higher unit sales during the summer when we receive peak pricing, and higher year–over–year gas pricing. 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.

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 currently conduct operations in California near known wildfire and mudslide areas and earthquake fault zones. A future natural disaster, such as a fire, mudslide 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. 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 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 exploration and production 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 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 failures and cyberattacks could affect us significantly.

We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. Without accurate data from and access to these systems and networks, our ability to communicate and control and manage our business could be adversely affected.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. 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 from occurring. If security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations. 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.

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. 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.

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 2022 capital expenditure budget of approximately $125 to $135 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. 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 2022 capital expenditures with cash flows from our operations, supplemented by cash on hand which was built as excess Levered Free Cash Flow during 2020 and 2021; however, our cash flows from operations, and access to capital should such cash flows and cash on hand prove inadequate, are subject to a number of variables, including:

- the volume of hydrocarbons we are able to produce from existing wells;
- 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 RBL Facility;
- and our ability to access the capital markets.

If our revenues or the borrowing base under the 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 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.

Although inflation in the United States has been relatively low in recent years, it rose significantly in the second half of 2021. This is believed to be the result of the economic impact from the COVID-19 pandemic, including the global supply chain disruptions and the government stimulus packages, among other factors. Global, industry-wide supply chain disruptions caused by the COVID-19 pandemic have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase as well as scarcity of certain products and raw materials. We are experiencing some inflationary pressure for certain costs, including employees and vendors, although such cost increases did not materially impact our 2021 financial condition or results of operations, and we currently do not expect them to materially impact our 2022 financial results or operations. However, to the extent elevated inflation remains, 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 operation.

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 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. 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 to meet the hedging requirements of the 2021 RBL Facility, which 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 (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.

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, 2021, we have hedged gas purchases at the following approximate volumes and prices: 34.9 mmbtu/d at $3.29 per mmbtu in 2022.

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 RBL Facility is subject to periodic redeterminations and our lenders could reduce capital available to us for investment.

The 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 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.

The amount available to be borrowed under the 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 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 RBL Facility. For example, the 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 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 RBL Facility to the extent that after a redetermination our outstanding borrowings at such time exceed the redetermined borrowing base. For additional details regarding the terms of the RBL Facility and our 2026 Notes, see "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, 2021, we had $400 million outstanding on our 2026 Notes and no outstanding borrowings under our 2021 RBL Facility, with approximately $193 million of available borrowings capacity. Our ability to make scheduled payments on or to refinance our debt obligations, including the RBL 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 RBL 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. For example, in the first quarter of 2020, we recorded a non-cash pre-tax asset impairment charge of $289 million on proved properties in Utah and certain California locations.

Changes in the method of determining London Interbank Offered Rate ("LIBOR"), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

Amounts drawn under the RBL Facility may bear interest rates in relation to LIBOR, depending on our selection of repayment options. On July 27, 2017, the Financial Conduct Authority in the U.K. announced that it would phase out LIBOR as a benchmark by the end of 2021. If LIBOR ceases to exist, we may need to renegotiate the RBL Facility and may not be able to do so with terms that are favorable to us. The overall financial market may be disrupted as a result of the phase-out or replacement of LIBOR.

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, 2021, sales to Tesoro Refining and Marketing, PBF Holding, Kern Oil & Refining, and Phillips 66accounted for approximately 30%, 16%, 14%, and 12% 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 potentially 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, and reduce the amount of oil and natural gas that we can produce from our wells below levels that would otherwise be possible. 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 2022. 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, Governor Gavin Newsom 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 greenhouse gases, 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. 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 “Item 1A. Risk Factors—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, results of operations and Prospects" and “Item 1A. Risk Factors—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. For instance, in 2021 we paid $19 million in asset retirement obligations, an increase from $18 million in 2020, largely due to the new idle well regulations and EH&S focused costs and initiatives associated with developing existing fields. 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 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 exploration and production 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 (“CWA”) has been subject to substantial uncertainty in recent years, which has the potential to increase permitting burdens. In 2015, the EPA and the U.S. Army Corps of Engineers (“Corps”) issued a rule expanding the scope of the term “Waters of the United States” (“WOTUS”) to include certain areas not traditionally considered to be subject to federal jurisdiction (the “Clean Water Rule”). Subsequently, in January 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrowed the definition of jurisdictional WOTUS relative to the Clean Water Rule. Both of these rulemakings have been subject to legal challenge, and the Biden Administration has announced plans to establish its own definition of

WOTUS. Most recently, the EPA and the Corps published a proposed rulemaking to revoke the 2020 rule in favor of a pre-2015 definition until a new definition is proposed which the Biden Administration has announced is underway. Additionally, in January 2022, the Supreme Court agreed to hear a case on the scope and authority of the Clean Water Act and the definition of WOTUS. As a result of these developments, the scope of the CWA is uncertain at this time. To the extent any rule expands the range of properties subject to the CWA's jurisdiction, 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 California governor or 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. For example, the Biden administration has set forth several tax proposals that would, if enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to, (i) an increase in the U.S. income tax rate applicable to corporations and (ii) the elimination of tax subsidies, generally in the form of accelerated deductions, for fossil fuels. Congress could consider some or all of these proposals in connection with tax reform to be undertaken by the Biden administration. 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 exploration and production 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 exploration and production 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 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. In September 2020, the Trump Administration revised prior regulations to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations. However, subsequently, the U.S. Congress approved, and President Biden signed into a law, a resolution to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In response to President Biden's executive order, in November 2021, the EPA issued a proposed rule that, if finalized, would establish new source and first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance to include leak detection using optical gas imaging and subsequent repair requirement, and reduction of emissions by 95% through capture and control systems. The EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of a final rule by the end of the year. We cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

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 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 LCFS and associated tradable credits that require a progressively lower carbon intensity of the state's fuel supply than baseline gasoline and diesel fuels. 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 September 2018, California adopted a law committing California , the fifth largest economy in the world, to the use of 100% zero-carbon electricity by 2045, and the Governor of California also signed an executive order committing California to total economy-wide carbon neutrality by 2045. In furtherance of these goals, Governor Newsom issued an order to CalGEM in April 2021, directing the agency to initiate regulatory action to end the issuance of new permits for hydraulic fracturing by January 2024. Additionally, Governor Newsom requested that the CARB analyze pathways to phase out oil extraction across the state by no later than 2045. 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 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; for more information, see our regulatory disclosure titled "Air Emissions". 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 our regulatory disclosure titled "Hydraulic Stimulation". 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 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 cities and other local governments 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, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Subsequently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Although we cannot predict the effects of these actions, 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, the Securities and Exchange Commission announced its intention to promulgate rules requiring climate disclosures.

Although the form and substance of these requirements is not yet known, this may result in additional costs to comply with any such disclosure requirements.

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, there are increasing risks to operations resulting from the potential physical impacts of climate change, such as drought, wildfires, damage to infrastructure and resources from flooding and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

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.

Our director who is 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.

Certain of our largest stockholders were creditors of Berry LLC prior to the Chapter 11 Proceedings and 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. In addition, we registered shares of the great majority of our common stock for resale. For more information see Exhibit 4.4 to our Annual Report on Form 10-K.

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.

Shares of our common stock are also reserved for issuance as equity-based awards to employees, directors and certain other persons under the second amended and restated 2017 Omnibus Incentive Plan (our “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 our 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 Omnibus Plan in the future.

The payment of dividends will be at the discretion of our board of directors.

We temporarily discontinued our quarterly dividends in the second quarter 2020 following the historic oil price drop and economic impact of COVID-19. We reinstated a quarterly dividend at a reduced rate beginning the first quarter of 2021 and then increased the rate 50% beginning with the third quarter of 2021. The Company's Board of Directors declared a regular dividend of $0.06 per share on the Company’s outstanding common stock, payable on April 15, 2022 to shareholders of record at the close of business on March 15, 2022. In addition, the Board implemented a shareholder return strategy that contemplates additional dividends to shareholders from discretionary cash flow, but there is no certainty that we will generate discretionary cash flow, nor is the Board 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. 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 operating expenses and other factors our Board deems relevant. Additionally, covenants contained in our RBL Facility and the indentures 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.

We are an "emerging growth company," and are able to take advantage of reduced disclosure requirements applicable to "emerging growth companies," which could make our common stock less attractive to investors.

We are an "emerging growth company" and, for as long as we continue to be an "emerging growth company," we intend to take advantage of certain exemptions from various reporting requirements, including auditor attestation requirements or any new requirements adopted by the Public Company Accounting Oversight Board (the "PCAOB") requiring mandatory audit firm rotation, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and exemptions from the requirements of holding a non-binding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We could be an "emerging growth company" for up to five years, or until the earliest of (i) the last day of the first fiscal year in which our annual gross revenues exceed $1.07 billion, (ii) as of the end of the fiscal year that we become a "large accelerated filer" as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), which would occur if the market value of our common stock that is held by non-affiliates exceeds $700 million as of the last business day of our most recently completed second fiscal quarter, or (iii) the date on which we have issued more than $1 billion in non-convertible debt during the preceding three-year period.

We intend to take advantage of the reduced reporting requirements and exemptions, including the longer phase-in periods for the adoption of new or revised financial accounting standards which lasts until those standards apply to private companies or we no longer qualify as an emerging growth company. Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those companies who will comply with new or revised financial accounting standards. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable.

To the extent investors find our common stock less attractive as a result of our reduced reporting and exemptions, there may be a less active trading market for our common stock, and our stock price may be more volatile.

Our internal control over financial reporting is not currently required to meet all of the standards required by Section 404 of the Sarbanes-Oxley Act, but 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.

Section 404 of the Sarbanes-Oxley Act requires us to provide annual management assessments of the effectiveness of our internal control over financial reporting. However, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act until we are no longer an "emerging growth company," which could be up to five years from our IPO.

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 our Annual Report on Form 10-K.

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 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, 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 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.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, 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 January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the 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 of 1933 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; plaintiffs’ opposition is due on March 21, 2022 and Defendants' reply is due on May 16, 2022.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Other Matters

For additional information regarding legal proceedings, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Commitments, and Contingencies*” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Contractual Obligations*.”

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 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 31 stockholders of record at January 31, 2022.

Dividend Policy

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

We first began paying a quarterly dividend paying 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 2020 following the historic oil price drop and economic impact of COVID-19. We reinstated a quarterly dividend at a reduced rate beginning the first quarter of 2021 and then increased the rate 50% beginning with the third quarter of 2021. Our Board declared a regular dividend at a rate of $0.06 per share on the Company’s outstanding common stock, payable on April 15, 2022 to shareholders of record at the close of business on March 15, 2022.

In early 2022, we implemented a new shareholder return model, for which we intend to allocate a significant portion of discretionary free cash flow to cash variable dividends to be paid quarterly. We expect remaining cash flows will be allocated to fund opportunistic debt repurchases, opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention. This new model is designed to significantly increase cash returns to our shareholders, further demonstrating Berry's commitment to be a leading returner of capital to its shareholders. Any dividends actually paid will be determined by our Board of Directors in light of existing conditions, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors.

Securities Authorized for Issuance Under Equity Compensation Plans

On June 27, 2018, our Board approved our second amended and restated 2017 Omnibus Incentive Plan (the “Omnibus Plan”). A description of the plans can be found in Item 8. Financial Statements and Supplementary Data – Note 6–Equity. The aggregate number of shares of our common stock authorized for issuance under stock-based compensation plans for our employees and non-employee directors is 10 million, of which 8.6 million have been issued or reserved through December 31, 2021.

The following table summarizes information related to our equity compensation plans under which our equity securities are authorized for issuance as of December 31, 2021.

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 ($)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (#)[3]
Equity compensation plans not approved by security holders[2]	6,998,815	N/A	1,368,778

(1) The number of securities to be issued upon vesting of unvested restricted stock units ("RSUs") subject to time vesting and performance-based restricted stock units ("PSUs"), assumes maximum achievement of certain market-based performance goals over a specified period of time.

(2) In connection with the IPO, our Board amended and restated the Company's First Amended and Restated 2017 Omnibus Incentive Plan, which had amended and restated the Company's 2017 Omnibus Incentive Plan (the "Prior Plans" and, collectively with the Omnibus Plan, the "Equity Compensation Plans"), which allowed us to grant equity-based compensation 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 the Prior Plans), to employees, consultants and directors of the Company and its affiliates who perform services for the Company. The Omnibus Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, stock awards, dividend equivalents and other types of awards.

(3) The number of securities remaining available for future issuances has been reduced by the number of securities to be issued upon settlement of RSUs subject to time vesting and PSUs assuming maximum achievement of certain market-based performance goals over a specified period of time.

Sales of Unregistered Securities

None

Stock Repurchase Program

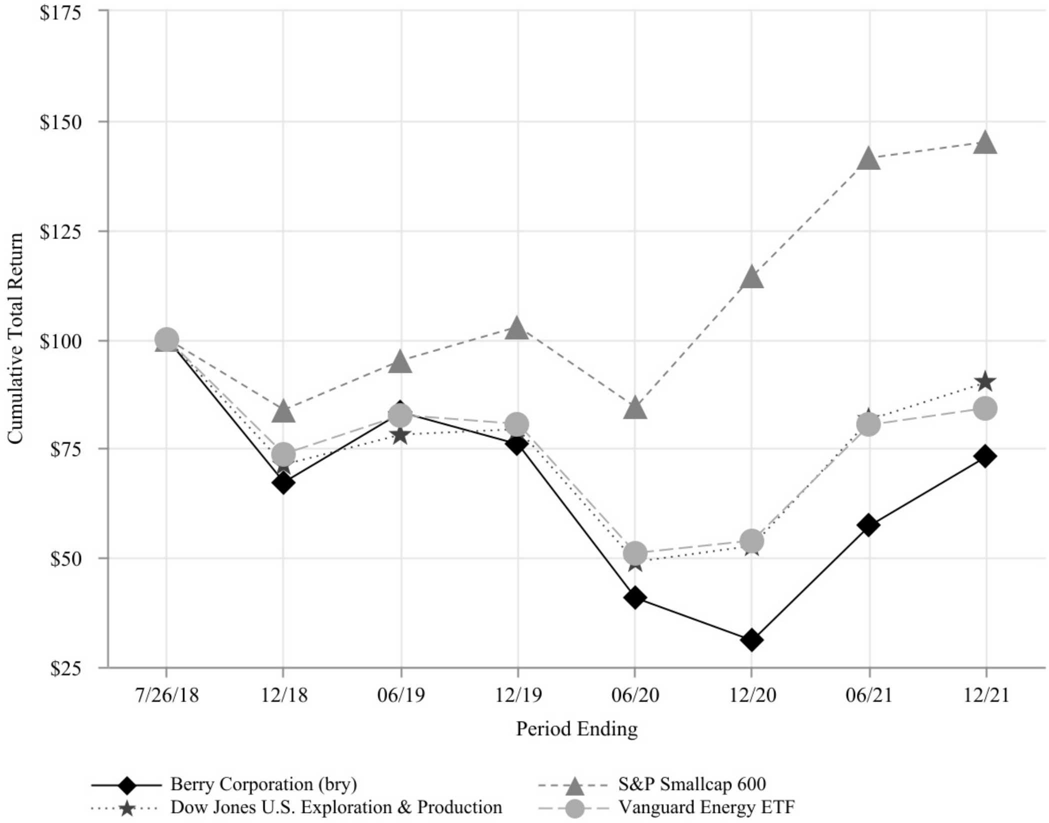
In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock at the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the year ended December 31, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million in the third quarter. All shares repurchased are reflected as treasury stock. Accordingly, as of December 31, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the program. The new shareholder return model that we implemented in January 2022 contemplates the potential use of a portion of discretionary free cash flow to opportunistically repurchase common stock.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P Smallcap 600, the Dow Jones U.S. Exploration and Production indexes and the Vanguard Energy ETF (with reinvestment of all dividends). The graph assumes that on July 26, 2018, the date our common stock began trading on the NASDAQ, $100 was invested in our common stock and in each index, and that all dividends were reinvested. The returns shown are based on historical results and are not intended to suggest future performance.

COMPARISON OF CUMULATIVE TOTAL RETURN[1][2]
Among Berry Corporation (bry), the S&P Smallcap 600 Index,
the Dow Jones U.S. Exploration & Production Index
and the Vanguard Energy ETF



	7/26/18	12/18	06/19	12/19	06/20	12/20	06/21	12/21
Berry Corporation (bry)	$ 100.00	$ 67.17	$ 83.16	$ 75.90	$ 40.66	$ 30.98	$ 57.25	$ 72.98
S&P Smallcap 600	$ 100.00	$ 83.66	$ 95.12	$ 102.72	$ 84.38	$ 114.32	$ 141.26	$ 144.98
Dow Jones U.S. Exploration & Production	$ 100.00	$ 71.18	$ 78.12	$ 79.29	$ 49.00	$ 52.61	$ 81.45	$ 89.92
Vanguard Energy ETF	$ 100.00	$ 73.67	$ 82.49	$ 80.50	$ 51.03	$ 53.89	$ 80.32	$ 84.17

(1) The performance graph shall not be deemed "soliciting material" or to be "filed" with the SEC for purposes of Section 18 of the Exchange Act, or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of the

Company under the Securities Act of 1933, as amended (the "Securities Act") or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

(2) $100 invested on July 26, 2018 in stock or June 30, 2018 in index, including reinvestment of dividends.

Item 6. Selected Financial Data

Not applicable

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 2021 and 2020 items and year-to-year comparisons between those years. For discussion of our year ended December 31, 2019, as well as the year ended 2020 compared to year ended 2019, refer to *Part II, Item 7— "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2020 Annual Report on Form 10-K*.

Executive Overview

We are a western United States independent upstream energy company focused on the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California. As further discussed below, in the fourth quarter of 2021, we diversified our operations with the acquisition of a business with well servicing and abandonment capabilities. As of October 1, 2021, we have operated in two business segments: (i) development and production ("D&P") (ii) well servicing and abandonment. The development and production segment is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah. On October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California, which became a reportable segment (well servicing and abandonment) under U.S. GAAP.

Our upstream development and production assets, in the aggregate, are characterized by high oil content, with 100% oil content for our California assets, and are in rural areas with low population. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. For example, the cost to drill and complete the different types of our wells in California is approximately $400,000 per well. The vertical wells in Utah operations cost approximately $1.5 million per well. In contrast, wells in typical unconventional resource plays cost $5 million to $10 million to drill and complete. The California oil market has Brent-linked pricing which in recent history realizes premium pricing to WTI. In the past five years Brent pricing has averaged almost $5 above WTI. All of our California assets are located in the 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 substantial data produced over the basin's long history, its reservoir characteristics are well understood, which enables predictable, repeatable, low geological risk and low-cost development opportunities. We also have upstream assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah. In January 2022, we divested our natural gas properties in the Piceance basin of Colorado.

In the fourth quarter of 2021, we acquired one of the largest upstream well servicing and abandonment businesses in California, which operates as C&J Well Services. This acquisition creates a strategic growth opportunity for Berry. It 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 Well Services is critical to advancing our strategy to work with the State of California to reduce fugitive emissions - including methane and carbon dioxide - from idle wells. We believe that C&J Well Services is uniquely positioned to capture both state and federal funds to help remediate orphan idle wells (an idle well that has been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well), and there are approximately 35,000 idle wells estimated to be in California according to third-party sources.

Since our Initial Public Offering in 2018, we have demonstrated our commitment to returning a substantial amount of capital to shareholders, delivering $134 million to our shareholders through dividends and share repurchases through 2021. In 2022, we initiated a new shareholder return model, which is designed to significantly increase cash returns to our shareholders from our discretionary free cash flow, which we define as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. Like our business model, this new shareholder returns model is simple and further demonstrates our commitment to return capital to our shareholders.

We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling locations with attractive full-cycle economics will support our objectives to generate Levered Free Cash Flow to fund our operations, optimize capital efficiency, and return meaningful capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles.

As part of our commitment to creating long-term value for our stockholders, we are dedicated to conducting our operations in an ethical, safe and responsible manner, to protecting the environment, and to taking care of our people and the communities in which we live and operate.

How We Plan and Evaluate Operations

We use “Levered Free Cash Flow” in planning our capital allocation to sustain production levels and fund internal growth opportunities, as well as determine our strategic hedging needs (we also hedge to meet the hedging requirements of the 2021 RBL Facility). Levered Free Cash Flow is a non-GAAP financial measure that we define as Adjusted EBITDA less capital expenditures, interest expense and dividends. Adjusted EBITDA is also a non-GAAP financial measure that is discussed and defined below.

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) shareholder returns; (c) operating expenses; (d) environmental, health & safety (“EH&S”) results; (e) general and administrative expenses; (f) production; and (g) well servicing and abandonment operations performance. With respect to our development and production business, we also measure oil and gas production levels. For our well services and abandonment business, we measure their performance through 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 our business. Adjusted EBITDA is a non-GAAP financial measure that we define as earnings before interest expense; income taxes; depreciation, depletion, and amortization (“DD&A”); derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items.

Shareholder Returns

In early 2022, we implemented a new shareholder return model, for which we intend to allocate a significant portion of discretionary free cash flow to cash variable dividends to be paid quarterly. The model is based on our discretionary free cash flow, which is defined as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. We expect remaining cash flows will be allocated to fund opportunistic debt repurchases, opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention. Our focus on shareholder returns is also demonstrated through our performance-based restricted stock awards, which are based on the Company's average cash returned on invested capital.

Operating Expenses

Overall, operating expense is used by management as a measure of the efficiency with which operations are performing. With respect to our production business, we define operating expenses as lease operating expenses, electricity generation expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Taxes other than income taxes and costs of services are excluded from operating expenses. Marketing revenues represent sales of natural gas purchased from and sold to third parties. The electricity, transportation and marketing activity related revenues are viewed and treated internally as a reduction to operating costs when tracking and analyzing the economics of development projects and the efficiency of our hydrocarbon recovery. Additionally, we strive to minimize the variability of our fuel gas costs for our California steam operations with gas hedges, and more recently agreements to transport fuel gas from the Rockies which have historically been cheaper than the California markets.

Environmental, Health & Safety

Like other companies in the oil and gas industry, both our production and well services operations are subject to complex and stringent federal, state and local laws and regulations relating to drilling, completion, well stimulation, well servicing, operation, maintenance or abandonment of wells or facilities, managing energy, water use, land use, managing greenhouse gases or other emissions, governing the discharge of materials into the environment or otherwise relating to environmental protection, including air quality, and the transportation, marketing, and sale of our products.

With respect to our production operations, current and future laws and regulations, as well as legislative and regulatory changes and other government activities, can materially impact our development, production, well servicing and abandonment plans, including by restricting the production rate of oil, natural gas and NGLs below the rate that would otherwise be possible. Additionally, the regulatory burden on the industry increases the cost of doing business and consequently effects capital expenditures and earnings.

As part of our commitment to creating long-term stockholder value, we strive to conduct our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate and our other stakeholders in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with existing laws and regulations.

We have a progressive approach to growing and evolving our businesses in today's dynamic oil and gas industry. Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safer, more efficient and lower emission operations. 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 monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics, including with respect to health and safety and spill prevention, is a part of our short-term incentive program for all employees.

General and Administrative Expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities and approximately 9% of such costs are capitalized, which is significantly less than industry norms. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

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

Well Servicing and Abandonment Operations Performance

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

Business Environment and Market Conditions

Our operating and financial results, and those of the oil and gas industry as a whole, are heavily influenced by commodity prices. Oil and gas prices and differentials have, and may continue to, fluctuate significantly as a result of numerous market-related variables, including global geopolitical and economic conditions. While oil prices have improved in 2021 and into 2022, they still remain volatile.

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. Additionally, our customers' requirements to plug and abandon wells is largely driven by regulatory requirements that is less dependent on commodity prices.

The recent recovery in the oil and gas industry has improved with increasing oil prices as demand increases with more states and countries re-opening and national and global economies continuing to recover from the global COVID-19 pandemic. The demand for oil, while improving as the ability of the global industry to grow supply diminishes, could again decline if there is a widespread resurgence of the COVID-19 outbreak. The extent to which our operating and financial results of future periods will be adversely impacted by the ongoing COVID-19 pandemic and the actions of foreign oil and gas producers will depend largely on future developments, which are highly uncertain and cannot be accurately predicted. Further, to what extent these events do ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors that are not within our control and cannot be predicted, including the duration and extent of the pandemic and speculation as to future actions by OPEC+. We were proactive in taking steps to address the challenges and mitigate repercussions from both the COVID-19 pandemic and industry downturns on our operations, our financial condition and our people.

As we focused on managing our business and operations in response to this health and economic crisis, the safety and well-being of our employees and the communities in which we operate remained our top priority. We are committed to being a good corporate citizen and demonstrated this commitment by focusing on the well-being of our employees and communities, including maintaining our strong safety and environmental standards and investing in community impact initiatives.

Because the visibility of the long-term supply and demand for oil has improved, we reinstated the quarterly dividend in the first quarter of 2021, which had been temporarily suspended in 2020, increased the dividend beginning the third quarter of 2021, and repurchased treasury shares during the year. Since our Initial Public Offering in 2018, we have demonstrated our commitment to returning a substantial amount of capital to shareholders, delivering $134 million to our shareholders through dividends and share repurchases through 2021. In 2022, we initiated a new shareholder return model, which is designed to significantly increase cash returns to our shareholders from our discretionary free cash flow, which we define as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. Like our business model, this new shareholder returns model is simple and further demonstrates our commitment to return capital to our shareholders.

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.

Average oil prices were higher for the year ended December 31, 2021 compared to the year ended December 31, 2020. Brent crude oil contract prices ranged from $51.09 per bbl to $86.40 per bbl and averaged $70.95 per bbl during the year. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics.

In California, the price we have typically paid for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $120.13 per mmbtu in February due to the effects of Winter Storm Uri, and as low as $2.37 per mmbtu during 2021, while we paid an average of $5.64 per mmbtu for the year.

The following table presents the average Brent, WTI, Kern Delivered, and Henry Hub prices for the years ended December 31, 2021 and 2020:

	Year Ended December 31,	
	2021	2020
Brent oil ($/bbl)	$ 70.95	$ 43.21
WTI oil ($/bbl)	$ 67.90	$ 39.59
Kern, Delivered natural gas ($/mmbtu)	$ 5.65	$ 2.46
Henry Hub natural gas ($/mmbtu)	$ 3.89	$ 2.03

As mentioned above, California oil prices are Brent-influenced as California refiners import approximately 65% to 70% of the state’s demand from OPEC+ countries and other waterborne sources. Without the higher costs and potential environmental impact associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, in appropriate oil price environments, should continue to allow us to realize positive cash margins in California over the cycle.

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

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. Natural gas prices were strong in 2021 and we expect will continue to exhibit strength in 2022 based on current and projected supply and demand balances. In recent history, the California gas markets have generally had higher gas prices than the Rockies and the rest of the United States. Higher gas prices have a negative impact on our operating results. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. We also strive to minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of such gas purchases. In addition, we recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that help limit our exposure to fuel gas purchase price fluctuations. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies.

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

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by two of our cogeneration facilities under long-term contracts with terms ending in July 2022 through December 2026. The most significant input and cost of the cogeneration facilities is natural gas. We generally receive significantly more revenue from these cogeneration facilities in the summer months, most notably in June through September, due to negotiated capacity payments we receive. In October 2021 we sold Placerita, which included a cogeneration facility requiring significant fuel gas purchases, and generated significant amount of electricity throughout the year, especially in the summer months.

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

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”.

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, 2021 and 2020.

	Year Ended December 31,	
	2021	2020
Average daily production:[1]		
Oil (mbbl/d)	24.2	25.0
Natural Gas (mmcf/d)	17.1	18.5
NGLs (mbbl/d)	0.4	0.4
Total (mboe/d)[2]	27.4	28.5
Total Production:		
Oil (mbbl)	8,825	9,176
Natural gas (mmcf)	6,224	6,766
NGLs (mbbl)	141	131
Total (mboe)[2]	10,004	10,435
Weighted-average realized prices:		
Oil without hedges ($/bbl)	$ 66.57	$ 39.56
Effects of scheduled derivative settlements ($/bbl)	$ (16.45)	$ 16.51
Oil with hedges ($/bbl)	$ 50.12	$ 56.07
Natural gas ($/mcf)	$ 5.27	$ 2.08
NGLs ($/bbl)	$ 36.64	$ 12.57
Average Benchmark prices:		
Oil (bbl) – Brent	$ 70.95	$ 43.21
Oil (bbl) – WTI	$ 67.90	$ 39.59
Gas (mmbtu) – Kern, Delivered[3]	$ 5.65	$ 2.46
Natural gas (mmbtu) – Henry Hub[4]	$ 3.89	$ 2.03

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 per mmbtu respectively.

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

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

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

	Year Ended December 31,	
	2021	**2020**
Average daily production (mboe/d)[1]:		
California[2]	22.0	22.9
Utah	4.2	4.3
	26.2	27.2
Colorado[3]	1.2	1.3
Total average daily production	27.4	28.5

(1) Production represents volumes sold during the period.

(2) Includes production for Placerita properties though the end of October 2021 when they were divested. These properties had average daily production in 2021 of over 800 boe/d prior to the sale.

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

Average daily production increased each quarter throughout 2021 and the last quarter of 2021 was 5% higher than the last quarter of 2020. This is indicative of the positive response from our assets with strategic capital deployment. The year-over-year production results were impacted by a significant capital reduction in 2020 in response to the significant decline in oil price and the measured ramp up in activity in early 2021. Oil production decreased 4% for the year ended December 31, 2021 compared to the year ended December 31, 2020, however the fourth quarter 2021 exit rate was 6% higher than the prior year. As a result of the 2021 development campaign in Utah, the year-over-year production in Utah was essentially flat compared to the decline of 14% in 2020.

Summary by Area

The following table shows a summary by area of our selected historical financial and operating information for our development and production operations.

	California (San Joaquin and Ventura basins)(3)		Utah (Uinta basin)		Colorado (Piceance basin)(4)	
	Year Ended December 31,		Year Ended December 31,		Year Ended December 31,	
($ in thousands, unless noted otherwise)	2021	2020	2021	2020	2021	2020
Oil, natural gas and natural gas liquids sales	$ 540,782	$ 335,642	$ 69,968	$ 37,481	$ 14,705	$ 5,537
Operating income (loss)(1)	$ 74,247	$ (7,915)	$ 30,128	$ (126,289)	$ 11,570	$ (357)
Depreciation, depletion, and amortization (DD&A)	$ 138,969	$ 130,388	$ 1,795	$ 7,058	$ 152	$ 324
Impairment of oil and gas properties	$ —	$ 163,879	$ —	$ 125,206	$ —	$ —
Average daily production (mboe/d)	22.0	22.9	4.2	4.3	1.2	1.3
Production (oil % of total)	100%	100%	51%	50%	2%	2%
Realized sales prices:						
Oil (per bbl)	$ 67.27	$ 40.01	$ 59.49	$ 34.81	$ 53.22	$ 24.01
NGLs (per bbl)	$ —	$ —	$ 36.64	$ 12.57	$ —	$ —
Gas (per mcf)	$ —	$ —	$ 4.94	$ 2.22	$ 5.76	$ 1.87
Capital expenditures(2)	$ 104,485	$ 65,456	$ 16,289	$ 1,247	$ 1	$ 206
Total proved reserves (mmboe)	79	87	14	7	4	1

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

(2) Excludes corporate capital expenditures.

(3) Includes production for Placerita properties, in the Ventura basin, though the end of October 2021 when they were divested. These properties had average daily production in 2021 of over 800 boe/d prior to the sale.

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

Results of Operations

	Year Ended December 31, 2021	Year Ended December 31, 2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$ 625,475	$ 378,663	$ 246,812	65 %
Services revenue	35,840	—	35,840	100 %
Electricity sales	35,636	25,813	9,823	38 %
(Losses) gains on oil and gas sales derivatives	(156,399)	117,781	(274,180)	n/a
Marketing and other revenues	4,398	1,576	2,822	179 %
Total revenues and other	$ 544,950	$ 523,833	$ 21,117	4 %

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 2021, our unhedged realized oil price was $66.57 per bbl and the hedged price was $50.12 per bbl. By comparison, in 2020, our unhedged realized oil price was $39.56 per bbl and our hedged price was $56.07 per bbl.

Oil, natural gas and NGL sales increased by $247 million, or 65%, to approximately $625 million for the year ended December 31, 2021 when compared to the year ended December 31, 2020. The increase was driven by $242 million and $20 million of higher prices for oil and natural gas, respectively, partially offset by a $15 million decrease in volumes.

Services revenue in 2021 consisted entirely of revenue from the Well Servicing and Abandonment business we acquired on October 1, 2021.

Electricity sales which represent sales to utilities increased by $10 million, or 38%, to approximately $36 million for the year ended December 31, 2021 when compared to the year ended December 31, 2020. The increase was largely a result of 59% higher unit sales prices that were driven by higher natural gas prices, partially offset by slightly lower volumes sold.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. In the year ended December 31, 2021, settlement losses were $143 million and in 2020 settlements gains were $152 million. The change was due to higher prices relative to the derivative fixed prices in 2021 compared to 2020. The mark-to-market non-cash losses for the years ended December 31, 2021 and 2020 of $14 million and $34 million, respectively, were due to higher future prices relative to the derivative fixed prices at each year end.

Marketing and other revenues were higher for the year ended December 31, 2021, compared to the year ended December 31, 2020 due to higher average gas prices.

	Year Ended December 31, 2021	Year Ended December 31, 2020	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 236,048	$ 186,348	$ 49,700	27 %
Costs of services	28,339	—	28,339	100 %
Electricity generation expenses	23,148	16,608	6,540	39 %
Transportation expenses	6,897	6,938	(41)	(1)%
Marketing expenses	3,811	1,380	2,431	176 %
General and administrative expenses	73,106	77,696	(4,590)	(6)%
Depreciation, depletion and amortization	144,495	139,180	5,315	4 %
Impairment of oil and gas properties	—	289,085	(289,085)	(100)%
Taxes, other than income taxes	46,500	35,572	10,928	31 %
(Gains) losses on natural gas purchase derivatives	(38,577)	1,035	(39,612)	n/a
Other operating expense	3,101	5,781	(2,680)	(46)%
Total expenses and other	526,868	759,623	(232,755)	(31)%
Other (expenses) income:				
Interest expense	(31,964)	(34,295)	(2,331)	(7)%
Other, net	(247)	(28)	219	782 %
Total other (expenses) income	(32,211)	(34,323)	(2,112)	(6)%
Loss before income taxes	(14,129)	(270,113)	(255,984)	(95)%
Income tax expense (benefit)	1,413	(7,218)	8,631	120 %
Net loss	$ (15,542)	$ (262,895)	$ (247,353)	(94)%
Adjusted EBITDA[(6)]	$ 212,146	$ 244,430	$ (32,284)	(13)%
Adjusted Net Income (Loss)[(6)]	$ 21,072	$ 44,816	$ (23,745)	(53)%
Expenses per boe:[(1)]				
Lease operating expenses	$ 23.60	$ 17.86	$ 5.74	32 %
Electricity generation expenses	2.31	1.59	0.72	45 %
Electricity sales	(3.56)	(2.47)	1.09	44 %
Transportation expenses	0.69	0.66	0.03	5 %
Transportation sales	(0.05)	(0.01)	0.04	400 %
Marketing expenses	0.38	0.13	0.25	192 %
Marketing revenues	(0.39)	(0.14)	0.25	179 %
Derivative settlements (received) paid for gas purchases[(1)]	(5.09)	0.89	(5.98)	n/a
Total operating expenses	$ 17.89	$ 18.51	$ (0.62)	(3)%
Total unhedged operating expenses[(2)]	$ 22.98	$ 17.62	$ 5.36	30 %
Total non-energy operating expenses[(3)]	$ 13.12	$ 13.63	$ (0.51)	(4)%
Total energy operating expenses[(4)]	$ 4.77	$ 4.88	$ (0.11)	(2)%
General and administrative expenses[(5)]	$ 7.31	$ 7.45	$ (0.14)	(2)%
Depreciation, depletion and amortization	$ 14.44	$ 13.34	$ 1.10	8 %
Taxes, other than income taxes	$ 4.65	$ 3.41	$ 1.24	36 %

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

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

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.61 per boe and $1.94 per boe for the year ended December 31, 2021 and December 31, 2020, respectively.

(6) 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

Operating expenses, including hedge effects, decreased 3% or $0.62 per boe for the year ended December 31, 2021 from $18.51 for the year ended December 31, 2020 due to lower non-energy operating expenses and energy operating expenses. Operating expenses are defined above in "How We Plan And Evaluate Operations."

As a result of our efficiency initiatives implemented beginning in the second quarter of 2020, we achieved a positive and substantial impact on operating expenses throughout 2021 without compromising our safety standards. Through these initiatives, non-energy operating expense decreased approximately $11 million, $0.51 per boe, when compared to the prior year. Primary year-over-year cost reductions in lease operating expenses were driven by lower facility costs of $0.63 per boe and outside services of $0.21, partially offset by higher recompletions and well maintenance of $0.21 and other expenses. Energy operating expenses decreased $0.11 per boe in 2021 due to higher electricity revenue of $1.09 per boe partially offset by higher hedged fuel costs of $0.97 per boe. Fuel costs impact both lease operating expenses and electricity generation expenses. Average natural gas purchase price increased $3.10 per mmbtu, 2.2 times higher than that of 2020, which resulted in higher fuel expense, net of the benefit from lower consumption. Settled hedges in 2021 had an average fixed price of $2.80 and notional quantities of 46,000 mmbtu per day, resulting in hedge effects that offset a large portion unhedged fuel cost. Higher natural gas prices in 2021 resulted in increased electricity unit revenue compared to 2020.

Cost of services in 2021 consisted entirely of costs from the Well Servicing and Abandonment business we acquired on October 1, 2021.

Electricity generation expenses increased 45% to $2.31 per boe for the year ended December 31, 2021 from $1.59 for the year ended December 31, 2020 primarily driven by higher fuel cost. Increased fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements discussed elsewhere.

Gain or loss on natural gas purchase derivatives for the year ended December 31, 2021 and 2020 were a gain of $39 million and a loss of $1 million, respectively. The settlement gain for the year ended December 31, 2021 was $51 million, or $5.09 per boe, compared to a settlement loss of $9 million, or $0.89 per boe for same period in 2020, driven by higher gas prices in 2021 compared to 2020. The mark-to-market valuation gain or loss for each of the years ended December 31, 2021 and December 31, 2020 was a loss of $13 million and a gain of $8 million, respectively, consistent with the changes in futures prices at the end of each period. While, we allocate fuel costs to electricity generation and lease operating expenses, we do not allocate hedge effects specifically to these line items.

Transportation expenses decreased 5% to $0.69 per boe for the year ended December 31, 2021, compared to $0.66 for the year ended December 31, 2020, mainly due to lower volumes shipped from our Rockies assets.

Marketing expenses increased 192% to $0.38 per boe for the year ended December 31, 2021, compared to $0.13 per boe for the year ended December 31, 2020 due to higher gas prices. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased and sold to third parties.

General and administrative expenses decreased by approximately $5 million or 6%, for the year ended December 31, 2021 compared to the year ended December 31, 2020. This decrease includes lower non-cash stock compensation costs and non-recurring costs. For the year ended December 31, 2021 and 2020, non-cash stock compensation costs were approximately $13 million and $14 million, respectively, and non-recurring costs were approximately $3 million and $6 million, respectively. Non-recurring costs in 2021 consisted of legal and other professional services costs related to acquisition activity. In 2020, these costs primarily consisted of employee reorganization and termination costs and to a lesser degree costs associated with the volatile and depressed price environment.

Adjusted general and administrative expenses, which excluded non-cash stock compensation costs and non-recurring costs, were flat year-over-year, at $57 million despite the additional $3 million CJWS general and administrative expenses in the fourth quarter of 2021. Excluding the impact of CJWS, the $3 million year-over-year decrease in adjusted general and administrative expenses was primarily due to lower employee costs. Please see “—Non-GAAP Financial Measures” for a reconciliation of adjusted general and administrative expense to general and administrative expenses, the most directly comparable financial measures calculated and presented in accordance with GAAP.

DD&A increased by $5 million, or 4%, to approximately $144 million, for the year ended December 31, 2021 compared to the year ended December 31, 2020, due to the higher depreciation and depletion rates for 2021. On a per boe basis, year-over-year DD&A increased $1.10 to $14.44 from $13.34.

Impairment of Oil and Gas Properties

During 2021, we did not have any impairment charges. In the first quarter of 2020, we performed impairment tests with respect to our proved and unproved oil and gas properties as a result of significant declines in oil prices. As a result, we recorded a non-cash pre-tax asset impairment charge of $289 million on proved properties in Utah and certain California locations.

Taxes, Other Than Income Taxes

	Year Ended December 31,			
	2021	2020	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.83	$ 0.77	$ 0.06	8 %
Ad valorem taxes	1.73	1.62	0.11	7 %
Greenhouse gas allowances	2.09	1.02	1.07	105 %
Total taxes other than income taxes	$ 4.65	$ 3.41	$ 1.24	36 %

Taxes, other than income taxes, increased $1.24 to $4.65 per boe for the year ended December 31, 2021 compared to $3.41 for the year ended December 31, 2020. The increase was largely due to higher greenhouse gas mark-to-market prices during 2021. GHG prices began 2021 at $18 per metric ton and increased to $32 at year-end, and averaged $24 during 2021. During 2021, we experienced an increase in property taxes, as well as higher severance taxes due to increased revenue driven by higher product prices.

Other Operating Expense (Income)

For the years ended December 31, 2021 and 2020 other operating expenses were $3 million and $6 million, respectively. For the year ended December 31, 2021, other operating expenses mainly consisted of expensing approximately $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 of gain on the sale of properties and over $2 million of income from employee retention credits. For the year ended December, 31 2020, other operating expenses included $3 million of excess abandonment costs, $2 million of oil tank storage fees, and $1 million of drilling rig standby charges, partially offset by $1 million of tax and other refunds.

Interest Expense

Interest expense was comparable for the years ended December 31, 2021 and 2020.

Income Tax Expense (Benefit)

For the year ended December 31, 2021, we had income tax expense of approximately $1 million and a tax benefit of $7 million in 2020. The rates in 2021 and 2020 were impacted as we recorded valuation allowances on a large portion of our tax credits, net operating loss carryforwards and on other deferred tax assets as a result of estimated future realizability. The tax expense in 2021 included minimum taxes paid in California. Refer to Note 8 of the consolidated financial statements for more information about our income taxes.

Liquidity and Capital Resources

Currently, we expect to fund our 2022 capital expenditures with cash flows from our operations. As of December 31, 2021, we had liquidity of $215 million, consisting of $22 million cash on hand and $193 million available for borrowings under our 2021 RBL Facility. The 2021 RBL Facility has a borrowing base of $200 million with no further borrowing restrictions beyond the covenants summarized elsewhere. We also have $400 million in aggregate principal amount of 7.0% senior unsecured notes due February 2026 (the “2026 Notes”) outstanding, as further discussed below.

In the fourth quarter of 2021, we announced a new shareholder return model, which went into effect January 1, 2022, designed to increase cash returns to our shareholders, further demonstrating our commitment to be a leading returner of capital to its shareholders. The model is based on our discretionary free cash flow, which is defined as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. Under this new model, the company intends to allocate discretionary free cash flow on a quarterly basis as follows: (a) 60% predominantly in the form of cash variable dividends to be paid quarterly, as well as opportunistic debt repurchases; (b) 40% in the form of discretionary capital, to be used for opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention.

We currently believe that our liquidity, capital resources and cash on hand will be sufficient to conduct our business and operations for at least the next 12 months. 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 Levered Free Cash Flow we are currently generating and our liquidity and capital resources may not be sufficient to conduct our business and operations until commodity prices recover. Please see Part 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

On August 26, 2021, Berry Corp, as a guarantor, together with Berry LLC, as the borrower, entered into a credit agreement that provided for a revolving loan with up to $500 million of commitments, subject to a reserve borrowing base ("2021 RBL Facility"). Our initial borrowing base is $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. 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. In December 2021, we completed the first scheduled semi-annual borrowing base redetermination and entered into that certain First Amendment to Credit Agreement (the "First Amendment"), which resulted in a reaffirmed borrowing base at $200 million and changes to the hedging covenants in respect of the exclusion of short puts or similar derivatives in the calculation of minimum and maximum hedging requirements.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in certain lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base other than a result of a redetermination, we are required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base. In addition, the 2021 RBL Facility provides that if there are any outstanding borrowings and the consolidated cash balance exceeds $20 million at the end of each calendar week, such excess amounts shall be used to prepay borrowings under the credit agreement. Otherwise, any unpaid principal will be due at maturity.

The outstanding borrowings under the revolving loan bear interest at a rate equal to either (i) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% per annum, and (ii) a customary benchmark rate plus an applicable margin ranging from 3.0% to 4.0% per annum, and in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.5% on the average daily unused amount of the borrowing availability under the 2021 RBL Facility. We have the right to prepay any borrowings under the 2021 RBL Facility with prior notice at any time without a prepayment penalty.

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 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of December 31, 2021, our leverage ratio and current ratio were 2.0 to 1.0 and 2.2 to 1.0, respectively. In addition, the 2021 RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the 2021 RBL Facility as of December 31, 2021.

The 2021 RBL Facility contains usual and customary events of default and remedies for credit facilities of a similar nature. The 2021 RBL Facility also places restrictions on the borrower and its restricted subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of the borrower's senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

From and after August 26, 2022, the 2021 RBL Facility permits us to repurchase certain indebtedness if availability is equal to or greater than 20% of the borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

We can repurchase equity or make other distributions to our equity holders in an amount equal to (i) 100% of Free Cash Flow (as defined under the 2021 RBL Facility) for the fiscal quarter most recently ended prior to such repurchase or distribution minus (ii) the amount of certain investments made, so long as, in addition to other conditions and limitations as described in the 2021 RBL Facility, availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry LLC is the borrower on the 2021 RBL Facility and Berry Corp. is the guarantor. 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 “Guaranteed Obligations”). 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, 2021, we had no borrowings outstanding, $7 million in letters of credit outstanding, and approximately $193 million of available borrowings capacity under the 2021 RBL Facility.

2017 RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“2017 RBL Facility”). In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our 2017 RBL Facility, which resulted in a reaffirmed borrowing base at $200 million. On August 26, 2021, we cancelled the 2017 RBL Facility agreement. There were no borrowings outstanding at the time of cancellation.

Senior Unsecured Notes Offering

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

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. If we experience certain kinds of changes of control, holders of the 2026 Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the 2026 Notes, plus accrued and unpaid interest, if any.

The 2026 Notes are our 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 notes are fully and unconditionally guaranteed on a senior unsecured basis by us and will also be guaranteed by certain of our future subsidiaries; whereas Berry LLC, C&J Management and CJWS are not guarantors. The 2026 Notes and related guarantees are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under the RBL Facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the 2026 Notes.

The indenture governing the 2026 Notes contains restrictive covenants and customary events of default, including, among others, (a) non-payment; (b) non-compliance with covenants (in some cases, subject to grace periods); (c) payment default under, or acceleration events affecting, material indebtedness and (d) bankruptcy or insolvency events involving us or certain of our subsidiaries.

The 2026 Notes do not restrict us from making open market and other purchases of such notes.

Debt Repurchase Program

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

Hedges

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including swaps, puts and calls. 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.

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 (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.

We have also entered into Utah gas transportation contracts to help reduce the price fluctuation exposure, however these do not qualify as hedges. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. We expect our operations to generate sufficient cash flows at current commodity prices including our current hedging positions. For information regarding risks related to our hedging program, see “Item 1A. Risk Factors—Risks Related to Our Operations and Industry”.

As of February 11, 2022, we had the following crude oil production and gas purchases hedges.

	Q1 2022	Q2 2022	Q3 2022	Q4 2022	FY 2023	FY 2024
Brent						
Swaps						
Hedged volume (bbls)	976,500	1,117,500	1,104,000	1,104,000	3,055,750	732,000
Weighted-average price ($/bbl)	$ 69.79	$ 71.87	$ 71.84	$ 71.84	$ 71.55	$ 61.78
Put Spreads						
Long $50/$40 Put Spread hedged volume (bbls)	405,000	409,500	414,000	414,000	2,555,000	1,647,000
Short $50/$40 Put Spread hedged volume (bbls)	45,000	45,500	46,000	46,000	365,000	366,000
Collars						
Purchased Puts hedged volume (bbls)	270,000	—	—	—	1,095,000	—
Weighted-average price ($/bbl)	$ 40.00	$ —	$ —	$ —	$ 40.00	$ —
Sold Calls hedged volume (bbls)	270,000	—	—	—	1,095,000	—
Weighted-average price ($/bbl)	$ 80.00	$ —	$ —	$ —	$ 106.33	$ —
Henry Hub						
Purchased Puts						
Hedged volume (mmbtu)	1,800,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 2.75	$ —	$ —	$ —	$ —	$ —
Purchased Calls						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Sold Puts						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75

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

	Year Ended December 31,	
	2021	2020
Crude Oil (per bbl):		
Realized sales price, before the effects of derivative settlements	$ 66.57	$ 39.56
Effects of derivative settlements	$ (16.45)	$ 16.51
Realized sales price, after the effects of derivative settlements	$ 50.12	$ 56.07
Purchased Natural Gas (per mmbtu):		
Purchase price, before the effects of derivative settlements	$ 5.64	$ 2.55
Effects of derivative settlements	$ (2.16)	$ 0.35
Purchase price, after the effects of derivative settlements	$ 3.48	$ 2.90

Cash Dividends

Our Board of Directors approved regular cash dividends on our common stock of $0.04 per share for each of the first and second quarters of 2021 and $0.06 per share for each of the third and fourth quarters of 2021. For the year ended December 31, 2021 we paid approximately $11 million in cash dividends on our common stock. For the year ended December 31, 2020 we paid approximately $19 million in cash dividends on our common stock, which included payment of the dividend declared for the fourth quarter of 2019 and a $0.12 per share cash dividend for the first quarter of 2020. For the year ended December 31, 2019 we declared a cash dividend of $0.12 per share each quarter for a total of $0.48 per share and paid approximately $39 million in cash dividends on our common stock.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board’s evaluation of market conditions for our common stock at the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the year ended December 31, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million in the third quarter. All shares repurchased are reflected as treasury stock. Accordingly, as of December 31, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

Capital Program

Refer to Part II, Item 1 and 2. — “Our Capital Program” for details.

Acquisitions and Divestitures

C&J Well Services Acquisition (2021)

On October 1, 2021, we acquired one of the largest upstream well servicing and abandonment business in California, which operates as C&J Well Services, LLC. 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 C&J Well Services 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 C&J Well Services Acquisition creates a strategic growth opportunity and further aligns Berry with the State of California's energy transition goals, including to help reduce fugitive emissions, especially methane and carbon dioxide, from orphan and idle wells.

Placerita Divestiture (2021)

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

Piceance Divestiture (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 no material impact to the financial statements.

Antelope Creek Acquisition (2022)

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 700 boe/d.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Net cash:		
Provided by operating activities	$ 122,488	$ 196,529
Used in investing activities	(168,787)	(93,620)
Used in financing activities	(18,975)	(22,352)
Net (decrease) increase in cash and cash equivalents	$ (65,274)	$ 80,557

Operating Activities

Cash provided by operating activities decreased for the year ended December 31, 2021 by approximately $74 million when compared to the year ended December 31, 2020, and the most significant decreases consisted of a $234 million change in derivatives settlements paid and received, an increase of $56 million in unhedged operating expenses, which was mostly fuel gas costs on an unhedged basis, an increase of $28 million in cost of services related to CJWS, and a decrease of $51 million in working capital changes and other items. These cash decreases were mostly offset by increased sales, including CJWS sales, of $295 million.

Investing Activities

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

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Capital expenditures [1]		
Capital expenditures	(132,719)	(76,480)
Changes in capital expenditures accruals	482	(11,336)
Acquisitions, net of cash received	(50,568)	—
Acquisition of properties and equipment and other	(876)	(5,981)
Proceeds received from divestitures	14,025	—
Proceeds from sale of property and equipment and other	869	177
Net cash used in investing activities	$ (168,787)	$ (93,620)

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

Cash used in investing activities increased $75 million for the year ended December 31, 2021 when compared to the year ended December 31, 2020, primarily due to a $44 million increase in cash used for capital spending as we reinstated our development program in 2021. In 2021, we also had approximately $45 million more in expenditures for acquisitions than we did in 2020. These increases were partially offset by approximately $14 million of proceeds from divestitures in 2021.

Financing Activities

Cash used by financing activities decreased $3 million for the year ended December 31, 2021 when compared to the year ended December 31, 2020. In 2021, the cash used was primarily for dividends paid of $11 million, debt issuance costs related to the 2017 RBL Facility of $3 million, and the purchase of treasury stock of $2 million. In 2020, the cash used was primarily for dividends paid of $19 million.

Commitments, and Contingencies

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

We accrue for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at December 31, 2021 and December 31, 2020. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of accruals on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our 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, 2021, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We settled the lawsuit and the case was dismissed with prejudice on February 1, 2022 , which also satisfied the road obligation.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, 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 January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the 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 of 1933 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; plaintiffs’ opposition is due on March 21, 2022 and Defendants' reply is due on May 16, 2022.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of December 31, 2021:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:					
Processing and transportation contracts[1]	$ 97,082	$ 9,835	$ 19,478	$ 16,165	$ 51,604
Operating lease obligations	10,091	2,279	3,771	3,105	936
Other purchase obligations[2]	23,100	20,700	2,400	—	—
Total	$ 130,273	$ 32,814	$ 25,649	$ 19,270	$ 52,540

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

(2) Amounts included a purchase commitment of $6 million to build a road, which was classified as current. In January 2022 the purchase commitment of $6 million was fully resolved without any payment. Additionally, we have a drilling commitment in California, for which we are required to drill 57 wells with an estimated cost and minimum commitment of $17.1 million by April 2023. 49 of those wells are estimated at $14.7 million and are required to be drilled by December 2022.

Balance Sheet Analysis

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

	December 31, 2021		December 31, 2020	
	(in thousands)			
Cash and cash equivalents	$	15,283	$	80,557
Accounts receivable, net	$	86,269	$	52,027
Derivative instruments assets - current and long-term	$	1,070	$	2,507
Other current assets	$	45,946	$	19,400
Property, plant & equipment, net	$	1,301,349	$	1,258,084
Other non-current assets	$	6,562	$	7,235
Accounts payable and accrued expenses	$	157,524	$	151,985
Derivative instruments liabilities - current and long-term	$	48,202	$	23,321
Long-term debt	$	394,566	$	393,480
Deferred income taxes liability - long-term	$	1,831	$	1,011
Asset retirement obligation - long-term	$	143,926	$	135,192
Other non-current liabilities	$	17,782	$	785
Stockholders' equity	$	692,648	$	714,036

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

The $34 million increase in accounts receivable was driven mostly by $25 million in higher sales prices period-over-period and $18 million of accounts receivable related to CJWS which was acquired in the fourth quarter of 2021, partially offset by $9 million in lower hedge settlements outstanding at each period end.

The $26 million increase in net derivative assets and liabilities was due to the change from a net liability of $21 million in 2020 to a net liability of $47 million in 2021. Changes to mark-to-market derivative values at the end of each period result from differences in the forward curve prices relative to the contract fixed prices, changes in positions held and settlements received and paid throughout the periods.

The $26 million increase in other current assets was primarily due to $10 million of current assets from newly-acquired CJWS, $7 million of prepayments for development permits, $3 million of collateral for commitments, $6 million of prepaid deposits, $2 million of various other prepaid items, partially offset by a decrease in materials inventory of $2 million.

The $43 million increase in property, plant and equipment was largely the result of the $133 million in capital investments along with $35 million in asset retirement obligation and other additions, and $45 million of CJWS property, plant and equipment, offset by depreciation expense of $134 million as well as divestitures of $35 million.

The $1 million decrease in other non-current assets was primarily due to $3 million of unamortized debt issuance costs related to the cancellation of the 2017 RBL Facility, $3 million of amortization expense related to the 2021 RBL Facility and 2017 RBL Facility, offset by $4 million of cost incurred related to the issuance of the 2021 RBL Facility.

The $6 million increase in accounts payable and accrued expenses included $26 million of increased accruals and spending for various capital and operating costs due to the increased level of these activities at the end of each year, a $10 million increase in royalties accrued due to increased sales, and a $5 million increase in dividends payable, partially offset by a decrease of approximately $28 million in the current portion of the greenhouse gas liability due to a significant, scheduled payment in 2021, a decrease of $5 million in the current portion of asset retirement obligation and a decrease of $2 million taxes other than income tax liability.

The increase in long-term deferred income taxes liability was due to the income tax expense during the year.

The $9 million increase in the long-term portion of the asset retirement obligation from $135 million at December 31, 2020 to $144 million at December 31, 2021 was due to revised cost estimates of $32 million, $11 million of accretion, $5 million reclassified from short to long-term, and $1 million of liabilities incurred. These increases were partially offset by $22 million of reduction due to property sales and $18 million of liabilities settled during the period.

The $17 million increase in other non-current liabilities was driven by additional non-current greenhouse gas liabilities compared to prior year. At year-end 2020, the non-current portion of greenhouse gas liabilities was reclassified to current as the payments were due and paid in 2021.

The $21 million decrease in stockholders' equity was due to the net loss of $16 million, $16 million of common stock dividends declared, $2 million of treasury stock, and $2 million of shares withheld for payment of taxes on equity awards. These decreases were partially offset by $14 million of stock-based equity awards, net of taxes.

Non-GAAP Financial Measures

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

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

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

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

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

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

Adjusted General and Administrative Expenses is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period.

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

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

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Adjusted EBITDA reconciliation to net income (loss):		
Net loss	$ (15,542)	$ (262,895)
Add (Subtract):		
Interest expense	31,964	34,295
Income tax expense (benefit)	1,413	(7,218)
Depreciation, depletion, and amortization	144,495	139,180
Impairment of oil and gas properties	—	289,085
Losses (gains) on derivatives	117,822	(116,746)
Net cash (paid) received for scheduled derivative settlements	(87,625)	142,292
Other operating expenses	3,101	5,781
Stock compensation expense	13,783	14,630
Non-recurring costs	2,735	6,026
Adjusted EBITDA	$ 212,146	$ 244,430

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Adjusted EBITDA reconciliation to net cash provided by operating activities and Levered Free Cash Flow calculation:		
Net cash provided by operating activities	$ 122,488	$ 196,529
Add (Subtract):		
Cash interest payments	29,211	29,962
Cash income tax payments	699	222
Non-recurring costs	2,735	6,026
Other changes in operating assets and liabilities	57,013	11,691
Adjusted EBITDA	$ 212,146	$ 244,430
Subtract:		
Capital expenditures - accrual basis[(1)]	(132,719)	(76,480)
Interest expense	(31,964)	(34,295)
Fixed cash dividends declared	(16,297)	(9,564)
Levered Free Cash Flow[(2)]	$ 31,166	$ 124,091

(1) Capital expenditures on an accrual basis includes capitalized overhead and interest and excludes acquisitions. Also excluded is asset retirement spending of $19 million and $18 million for the years ended December 31, 2021 and 2020, respectively.

(2) Levered Free Cash Flow includes cash paid for scheduled derivative settlements of $88 million and cash received for scheduled derivative settlements of $142 million for the years ended December 31, 2021 and 2020, respectively.

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

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Adjusted Net Income (Loss) reconciliation to net (loss) income:		
Net loss	$ (15,542)	$ (262,895)
Add (Subtract): discrete income tax items	581	61,030
Add (Subtract):		
Losses (gains) on derivatives	117,822	(116,746)
Net cash (paid) received for scheduled derivative settlements	(87,625)	142,292
Other operating expenses	3,101	5,781
Impairment of oil and gas properties	—	289,085
Non-recurring costs	2,735	6,026
Total additions (subtractions), net	36,033	326,438
Income tax expense of adjustments at effective tax rate[(1)]	—	(79,757)
Adjusted Net Income (Loss)	$ 21,072	$ 44,816
Basic EPS on Adjusted Net Income	$ 0.26	$ 0.56
Diluted EPS on Adjusted Net Income	$ 0.25	$ 0.56
Weighted average shares outstanding - basic	80,209	79,802
Weighted average shares outstanding - diluted	83,496	79,902

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

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

	Year Ended December 31,			
	2021		2020	
	(in thousands)			
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:		**$/boe**		**$/boe**
General and administrative expenses	$ 73,106		$ 77,696	
Subtract:				
Non-cash stock compensation expense (G&A portion)	(13,356)		(14,264)	
Non-recurring costs	(2,735)		(6,026)	
Adjusted general and administrative expenses	$ 57,015		$ 57,406	
Development and production segment, and corporate	$ 53,822	$ 5.38	$ 57,406	$ 5.50
Well servicing and abandonment segment	$ 3,193		$ —	

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with generally accepted accounting principles 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 costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves. All development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved developed 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 $0.64 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, 2021 and 2020, the net capitalized costs attributable to unproved properties was approximately $292 million and $311 million, respectively. 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, 2021.

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. Following the October 1, 2021 acquisition of CJWS, 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.

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 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.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state taxing authorities. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and tax carryforwards. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. See Note 8 in the Notes to Consolidated Financial Statements in Part II—Item 8. Financial Statements and Supplementary Data of this report for a discussion of new accounting matters

Stock-based Compensation

We have issued restricted stock units ("RSUs") that vest over time and performance-based restricted stock units ("PSUs") that include (i) awards with a market objective measured against both absolute total stockholder return ("Absolute TSR") and a relative total stockholder return ("Relative TSR") (the "TSR PSUs") over the performance period and (ii) awards based on the Company's average cash returned on invested capital ("CROIC PSUs") over the performance period. 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 and CROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the peer group over the performance periods. 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.

Significant Accounting and Disclosure Changes

See Note 1 in the Notes to Consolidated Financial Statements in Part II—Item 8. Financial Statements and Supplementary Data of this report for a discussion of new accounting matters.

Inflation

Although inflation in the United States has been relatively low in recent years, it rose significantly in the second half of 2021. This is believed to be the result of the economic impact from the COVID-19 pandemic, including the global supply chain disruptions and the government stimulus packages, among other factors. Global, industry-wide supply chain disruptions caused by the COVID-19 pandemic have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase as well as scarcity of certain products and raw materials. We are experiencing some inflationary pressure for certain costs, including employees and vendors, although such cost increases did not materially impact our 2021 financial condition or results of operations, and we currently do not expect them to materially impact our 2022 financial results or operations. However, to the extent elevated inflation remains, 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 operation.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information included or incorporated by reference in this report includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, capital for sustained production levels, expected production and operating costs, reserves, hedging activities, capital expenditures, return of capital, improvement of recovery factors and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect us are discussed above in “Item 1A. Risk Factors” in this prospectus, in any applicable prospectus supplement and in the documents incorporated by reference.

Factors (but not necessarily 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, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- inflation levels, particularly the recent rise to historically high levels;
- the length, scope and severity of the ongoing COVID-19 pandemic or the emergence of a new pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, global supply chain disruptions and labor constraints;
- global economic trends, geopolitical risks and general economic and industry conditions, such as the economic impact from the COVID-19 pandemic, including the global supply chain disruptions and the government interventions into the financial markets and economy, among other factors;
- those resulting from the COVID-19 pandemic and from the actions of foreign producers, importantly including OPEC+ and change in OPEC+'s production levels;
- volatility of oil, natural gas and NGL prices;
- the California and global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;
- supply of and demand for oil, natural gas and NGLs, 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;
- 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;
- 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;
- effects of competition;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including wildfires, earthquakes and pandemics;
- environmental risks and liabilities under federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyberattacks; and.
- governmental actions and political conditions, as well as the actions by other third parties that are beyond our control.

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

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

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 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, 2021, the fair value of our hedge positions was a net liability of approximately $47 million. A 10% increase in the oil and natural gas index prices above the December 31, 2021 prices would result in a net liability of approximately $76 million; conversely, a 10% decrease in the oil and natural gas index prices below the December 31, 2021 prices would result in a net asset of approximately $2 million. For additional information about derivative activity, see Note 4, Derivatives, in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts. Additionally, we cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flows could be negatively impacted.

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 five commodity derivative counterparties at December 31, 2021 and nine at December 31, 2020. 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, with certain limited exceptions, the 2021 RBL Facility prevents us from entering into hedging arrangements that are secured (except with our lenders and their affiliates), that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A or 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, 2021 was not material and losses associated with credit risk have not been 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, 2021, we had no borrowings under our RBL Facility and thus we had no interest rate risk exposure. 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 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):

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Berry Corporation (bry) and subsidiaries (the Company) as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2021, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

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

Los Angeles, California
March 4, 2022

BERRY CORPORATION (bry)
CONSOLIDATED BALANCE SHEETS

	December 31, 2021	December 31, 2020
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,283	$ 80,557
Accounts receivable, net of allowance for doubtful accounts of $866 at December 31, 2021 and $2,215 at December 31, 2020	86,269	52,027
Derivative instruments	—	2,507
Other current assets	45,946	19,400
Total current assets	147,498	154,491
Noncurrent assets:		
Oil and natural gas properties	1,537,894	1,412,566
Accumulated depletion and amortization	(340,328)	(235,259)
Total oil and natural gas properties, net	1,197,566	1,177,307
Other property and equipment	140,710	112,145
Accumulated depreciation	(36,927)	(31,368)
Total other property and equipment, net	103,783	80,777
Derivative instruments	1,070	—
Other noncurrent assets	6,562	7,235
Total assets	$ 1,456,479	$ 1,419,810
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 157,524	$ 151,985
Derivative instruments	29,625	23,321
Total current liabilities	187,149	175,306
Noncurrent liabilities:		
Long-term debt	394,566	393,480
Derivative instruments	18,577	—
Deferred income taxes	1,831	1,011
Asset retirement obligation	143,926	135,192
Other noncurrent liabilities	17,782	785
Commitments and Contingencies - Note 5		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 85,590,417 and 85,041,581 shares issued; and 80,007,149 and 79,929,335 shares outstanding, at December 31, 2021 and December 31, 2020, respectively)	86	85
Additional paid-in capital	912,471	915,877
Treasury stock, at cost (5,583,268 shares at December 31, 2021 and 5,112,246 shares at December 31, 2020)	(52,436)	(49,995)
Retained deficit	(167,473)	(151,931)
Total stockholders' equity	692,648	714,036
Total liabilities and stockholders' equity	$ 1,456,479	$ 1,419,810

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2021	2020	2019
	(in thousands, except per share amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 625,475	$ 378,663	$ 565,596
Services revenue	35,840	—	—
Electricity sales	35,636	25,813	29,397
(Losses) gains on oil and gas sales derivatives	(156,399)	117,781	(37,998)
Marketing revenues	3,921	1,426	2,094
Other revenues	477	150	316
Total revenues and other	544,950	523,833	559,405
Expenses and other:			
Lease operating expenses	236,048	186,348	216,294
Costs of services	28,339	—	—
Electricity generation expenses	23,148	16,608	19,490
Transportation expenses	6,897	6,938	8,059
Marketing expenses	3,811	1,380	2,073
General and administrative expenses	73,106	77,696	62,643
Depreciation, depletion and amortization	144,495	139,180	106,006
Impairment of oil and gas properties	—	289,085	51,081
Taxes, other than income taxes	46,500	35,572	40,645
(Gains) losses on natural gas purchase derivatives	(38,577)	1,035	6,957
Other operating expense	3,101	5,781	4,588
Total expenses and other	526,868	759,623	517,836
Other (expenses) income:			
Interest expense	(31,964)	(34,295)	(34,234)
Other, net	(247)	(28)	80
Total other (expenses) income	(32,211)	(34,323)	(34,154)
Reorganization items, net	—	—	(426)
(Loss) income before income taxes	(14,129)	(270,113)	6,989
Income tax expense (benefit)	1,413	(7,218)	(36,550)
Net (loss) income	$ (15,542)	$ (262,895)	$ 43,539
Net (loss) earnings per share:			
Basic	$ (0.19)	$ (3.29)	$ 0.54
Diluted	$ (0.19)	$ (3.29)	$ 0.53

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 (Deficit) Earnings	Total Equity
			(in thousands)		
December 31, 2018	$ 82	$ 914,540	$ (24,218)	$ 116,042	$ 1,006,446
Shares withheld for payment of taxes on equity awards and other	—	(1,268)	—	—	(1,268)
Stock based compensation	—	8,826	—	—	8,826
Purchase of rights to common stock	—	(20,265)	20,265	—	—
Purchase of treasury stock	—	—	(46,042)	—	(46,042)
Common stock issued to settle unsecured claims	3	(3)	—	—	—
Dividends declared on common stock, $0.48/share	—	—	—	(39,053)	(39,053)
Net income	—	—	—	43,539	43,539
December 31, 2019	85	901,830	(49,995)	120,528	972,448
Shares withheld for payment of taxes on equity awards	—	(1,039)	—	—	(1,039)
Stock based compensation	—	15,086	—	—	15,086
Dividends declared on common stock, $0.12/share	—	—	—	(9,564)	(9,564)
Net loss	—	—	—	(262,895)	(262,895)
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

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Cash flow from operating activities:			
Net (loss) income	$ (15,542)	$ (262,895)	$ 43,539
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	144,495	139,180	106,006
Amortization of debt issuance costs	4,430	5,351	5,059
Impairment of oil and gas properties	—	289,085	51,081
Stock-based compensation expense	13,783	14,630	8,647
Deferred income taxes	819	(8,045)	(36,778)
(Decrease) increase in allowance for doubtful accounts	(1,349)	1,112	153
Other operating expenses	(487)	5,083	5,518
Derivatives activities:			
Total losses (gains)	117,822	(116,746)	44,955
Cash settlements on derivatives	(91,634)	142,292	42,197
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(15,614)	18,767	(14,597)
Increase in other assets	(24,824)	(2)	(5,136)
Decrease in accounts payable and accrued expenses	4,045	(14,172)	(917)
Decrease in other liabilities	(13,456)	(17,111)	(7,898)
Net cash provided by operating activities	122,488	196,529	241,829
Cash flow from investing activities:			
Capital expenditures:			
Capital expenditures	(132,719)	(76,480)	(211,995)
Changes in capital expenditures accruals	482	(11,336)	(11,159)
Acquisitions, net of cash received	(50,568)	—	—
Acquisition of properties and equipment and other	(876)	(5,981)	(2,840)
Proceeds received from divestitures	14,025	—	—
Proceeds from sale of property and equipment and other	869	177	969
Net cash used in investing activities	(168,787)	(93,620)	(225,025)
Cash flow from financing activities:			
Borrowings under RBL credit facility	119,000	228,900	355,132
Repayments on RBL credit facility	(119,000)	(230,750)	(353,282)
Dividends paid on common stock	(11,486)	(19,463)	(39,157)
Purchase of treasury stock	(2,440)	—	(46,909)
Shares withheld for payment of taxes on equity awards and other	(1,543)	(1,039)	(1,268)
Debt issuance costs	(3,506)	—	—
Net cash used in financing activities	$ (18,975)	$ (22,352)	$ (85,484)
Net (decrease) increase in cash and cash equivalents	(65,274)	80,557	(68,680)
Cash and cash equivalents:			
Beginning	80,557	—	68,680
Ending	$ 15,283	$ 80,557	$ —

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

BERRY CORPORATION (bry)
NOTES TO CONSOLIDATED 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 three 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 ("CJWS"). As the context may require, the "Company", "we", "our" or similar words refer to Berry Corp. and its consolidated subsidiary, Berry LLC, and as of October 1, 2021 this also includes CJWS and C&J Management.

As of October 1, 2021, we now operate in two business segments: (i) development and production (ii) well servicing and abandonment. The development and production segment is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah. On October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California, which became a reportable segment (wells servicing and abandonment) under U.S. GAAP.

Nature of Business

We are an independent upstream energy company focused on the development and production of onshore, low geologic risk, long-lived conventional oil reserves, primarily located in California, with newly acquired well servicing and abandonment capabilities in California.

Berry Corp. was incorporated under Delaware law in February 2017 and its common stock began trading on NASDAQ under the symbol "bry" in July 2018. Berry Corp. operates through its three wholly owned subsidiaries. Berry LLC owns and operates our oil and gas assets, all of which are located onshore in the United States (the "U.S."), in California (in the San Joaquin basin) and Utah (in the Uinta basin). In January 2022, we divested our natural gas properties in the Piceance basin of Colorado. Effective as of October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California (the "C&J Well Services Acquisition"), this business is owned and operated through CJWS.

Principles of Consolidation and Reporting

The consolidated financial statements have been 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 exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

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 Development and Production segment consists of the development and production of onshore, low geologic risk, long-lived conventional oil reserves, primarily located in California, as well as 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 costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves. All development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved developed 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 $2 million in 2021, $1 million in 2020, and $2 million in 2019. 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 and the amount of capitalized overhead was approximately $7 million, $6 million and $2 million in 2021, 2020 and 2019, 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, 2021 and 2020, the net capitalized costs attributable to unproved properties was approximately $292 million and $311 million, respectively. 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.

Impairment

In 2021 we did not record any impairment charges for proved and unproved properties.

As of March 31, 2020, we performed impairment tests with respect to our proved and unproved oil and gas properties and other property and equipment as a result of significant declines in oil prices during the latter part of the first quarter 2020. We recorded a non-cash pre-tax asset impairment charge of $289 million during the first quarter of 2020 on proved properties in Utah and certain California locations and other property and equipment. We evaluated our proved properties in accordance with accounting guidance and fair value techniques utilizing the period-end forward price curve, as well as assessing projects we determine we would not pursue in the foreseeable future given the current environment. We determined based on plans and exploration and development efforts no impairment was necessary for our unproved property balance in 2020.

At year end 2019, we evaluated our proved and unproved natural gas properties in regards to the decline in our expectations of future gas prices. As a result, we recorded a non-cash pre-tax asset impairment charge of $51 million for our Piceance gas properties in Colorado, of which $23 million was for proved properties and other property and equipment and $28 million for unproved properties.

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, 20 to 30 years for cogens, natural gas plants and pipelines, 1 to 10 years 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.

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. Following the October 1, 2021 acquisition of CJWS, we accounted for the various assets acquired and liabilities assumed 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 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 $144 million and $135 million were included in long term liabilities as of December 31, 2021 and December 31, 2020, respectively, with the remaining current portion included in accrued liabilities:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Beginning balance	$ 160,192	$ 149,227
Liabilities incurred including from acquisitions	1,350	5,919
Settlements and payments	(17,900)	(14,931)
Accretion expense	10,936	9,996
Reduction due to property sales	(22,199)	—
Revisions	31,546	9,981
Ending balance	$ 163,925	$ 160,192

Revenue Recognition

The majority of the Company's revenue is from the development and production 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 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 item on our balance sheet that would be affected by recurring fair value measurements is derivatives. We determine the fair value of our oil and gas sales and natural gas purchase derivatives using valuation techniques which utilize market quotes and pricing analysis. Inputs include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We 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) awards with a market objective measured against both absolute total stockholder return (“Absolute TSR”) and a relative total stockholder return (“Relative TSR”) (the “TSR PSUs”) over the performance period and (ii) awards based on the Company's average cash returned on invested capital (“CROIC PSUs”) over the performance period. 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 and CROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the peer group over the performance periods. 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

We computed basic and diluted earnings per share (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.

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. For basic EPS, the weighted-average number of common shares 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.

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, 2021, our four largest customers represented approximately 30%, 16%, 14%, and 12% of our sales, which are all customers of the development and production segment. For the year ended

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

December 31, 2020, our three largest customers represented 44%, 20%, and 12% of our sales. For the year ended December 31, 2019, our three largest customers represented approximately 36%, 24%, and 13% of our sales.

At December 31, 2021, trade accounts receivable from three customers represented approximately 28%, 13%, and 11% of our receivables, which are all customers of the development and production segment. At December 31, 2020, trade accounts receivable from three customers represented approximately 38%, 15%, and 11% of our receivables.

Recently Adopted Accounting Standards

In December 2019, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, which simplified the accounting for income taxes. We adopted these rules in the first quarter of 2021 which did not have a material impact on our financial statements.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which requires lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)*, which is an update to the lease standard providing an optional transition approach for land easements allowing entities to evaluate only new or modified land easements. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842)*, which provided optional transition relief allowing a prospective approach in applying the new rules by not adjusting comparative period financial information for the effects of the new rules and not requiring disclosures for periods before the effective date. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers. During the second quarter of 2020, this adoption date was further delayed by FASB until fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We will adopt these rules in 2022, which we expect to apply prospectively. We are currently evaluating the impact of the adoption of the new lease standard on our consolidated financial statements, including identifying all leases as defined under the new lease standards.

In March 2020, the FASB issued issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*, which provided optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by the reference rate reform, if certain criteria are met. The optional expedient for contract modifications applies to contract modifications that replace a reference rate affected by the reference rate reform, such as the London Interbank Offered Rate ("LIBOR"). Entities may elect to apply the amendments for contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020 through December 31, 2022. To date, these rules have not had any impact on our consolidated financial statements and we continue to assess the future impact of these rules 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:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Proved properties	$ 1,246,380	$ 1,101,371
Unproved properties	291,514	311,195
Total proved and unproved properties	1,537,894	1,412,566
Less accumulated depletion and amortization	(340,328)	(235,259)
Total proved and unproved properties, net	$ 1,197,566	$ 1,177,307

Other Property and Equipment

Other property and equipment consisted of the following:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Cogens, natural gas plants and pipelines	$ 54,237	$ 72,999
Vehicles and service equipment[(1)]	55,521	8,878
Furniture and equipment	22,665	21,515
Land	6,101	6,512
Buildings and leasehold improvements	2,186	2,241
Total other property and equipment	140,710	112,145
Less: accumulated depreciation	(36,927)	(31,368)
Total other property and equipment, net	$ 103,783	$ 80,777

(1) Includes CJWS vehicles and service equipment in 2021.

Note 3—Debt

The following table summarizes our outstanding debt:

	December 31, 2021	December 31, 2020	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ —	n/a	variable rates 5.3% (2021)	August 26, 2025	Mortgage on 90% of Present Value of proven oil and gas reserves and lien on certain other assets
2017 RBL Facility	n/a	$ —	variable rates 4.0% (2020)	July 29, 2022 (Cancelled August 26, 2021)	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on certain other assets
2026 Notes	400,000	400,000	7%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	400,000			
Less: Debt Issuance Costs	(5,434)	(6,520)			
Long-Term Debt, net	$ 394,566	$ 393,480			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At December 31, 2021 and 2020, debt issuance costs for the 2021 RBL Facility and 2017 RBL Facility (each as defined below) reported in “other noncurrent assets” on the balance sheet were approximately $5 million and $7 million, net of amortization, respectively. In 2021, we expensed $3 million of unamortized debt issuance costs related to the modification of the 2017 RBL Facility. Also in 2021, we incurred approximately $4 million of legal and bank fees related to the issuance of the 2021 RBL Facility. At December 31, 2021 and 2020, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the “2026 Notes”) reported in “Long-Term Debt, net” on the balance sheet were approximately $5 million and $7 million, respectively.

For the years ended December 31, 2021, 2020, and 2019, the amortization expense for the 2021 RBL Facility, the 2017 RBL Facility and the 2026 Notes combined, was approximately $4 million, $5 million, and $5 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 amount of each RBL Facility approximated fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 Notes was approximately $400 million and $337 million at December 31, 2021 and 2020, respectively.

2021 RBL Facility

On August 26, 2021, Berry Corp, as a guarantor, together with Berry LLC, as the borrower, entered into a credit agreement that provided for a revolving loan with up to $500 million of commitments, subject to a reserve borrowing base (“2021 RBL Facility”). Our initial borrowing base is $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. 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. In December 2021, we completed the first scheduled semi-annual borrowing base redetermination and entered into that certain First Amendment to Credit Agreement (the “First Amendment”), which resulted in a reaffirmed borrowing base at $200 million and changes to the hedging covenants in respect of the exclusion of short puts or similar derivatives in the calculation of minimum and maximum hedging requirements.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in certain lenders’ opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base other than a result of a redetermination, we are required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base. In addition, the 2021 RBL Facility provides that if there are any outstanding borrowings and the consolidated cash balance exceeds $20 million at the end of each calendar week, such excess amounts shall be used to prepay borrowings under the credit agreement. Otherwise, any unpaid principal will be due at maturity.

The outstanding borrowings under the revolving loan bear interest at a rate equal to either (i) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% per annum, and (ii) a customary benchmark rate plus an applicable margin ranging from 3.0% to 4.0% per annum, and in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.5% on the average daily unused amount of the borrowing availability under the 2021 RBL Facility. We have the right to prepay any borrowings under the 2021 RBL Facility with prior notice at any time without a prepayment penalty.

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 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of December 31, 2021, our leverage ratio and current ratio were 2.0 to 1.0 and 2.2 to 1.0, respectively. In addition, the 2021 RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the 2021 RBL Facility as of December 31, 2021.

The 2021 RBL Facility contains usual and customary events of default and remedies for credit facilities of a similar nature. The 2021 RBL Facility also places restrictions on the borrower and its restricted subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of the borrower’s senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

From and after August 26, 2022, the 2021 RBL Facility permits us to repurchase certain indebtedness if availability is equal to or greater than 20% of the borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We can repurchase equity or make other distributions to our equity holders in an amount equal to (i) 100% of Free Cash Flow (as defined under the 2021 RBL Facility) for the fiscal quarter most recently ended prior to such repurchase or distribution minus (ii) the amount of certain investments made, so long as, in addition to other conditions and limitations as described in the 2021 RBL Facility, availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry LLC is the borrower on the 2021 RBL Facility and Berry Corp. is the guarantor. 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 “Guaranteed Obligations”). 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, 2021, we had no borrowings outstanding, $7 million in letters of credit outstanding, and approximately $193 million of available borrowings capacity under the 2021 RBL Facility.

Corporate Organization

Berry Corp., as Berry LLC’s parent company, has no independent assets or operations and is subject to a passive holding company covenant under the 2021 RBL Facility. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than restrictions under the 2021 RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

The 2021 RBL Facility permits Berry Corp. to make dividends so long as both before and after giving pro forma effect to such distribution, no default or event of defaults exists, availability exceeds 20% of the borrowing base, whichever is in effect, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.0 to 1.0. The conditions are currently met with significant margin.

2017 RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“2017 RBL Facility”). In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our 2017 RBL Facility, which resulted in a reaffirmed borrowing base at $200 million. On August 26, 2021, we cancelled the 2017 RBL Facility agreement. There were no borrowings outstanding at the time of cancellation.

Senior Unsecured Notes Offering

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

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. If we experience certain kinds of changes of control, holders of the 2026 Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the 2026 Notes, plus accrued and unpaid interest, if any.

The 2026 Notes are our 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 notes are fully and unconditionally guaranteed on a senior unsecured basis by us and will also be guaranteed by certain of our future subsidiaries; whereas Berry LLC, C&J Management and CJWS are not guarantors. The 2026 Notes and related guarantees are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our RBL Facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the 2026 Notes.

The indenture governing the 2026 Notes contains restrictive covenants that may limit our ability to, among other things:

- 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; and
- engage in transactions with affiliates.

The indenture governing the 2026 Notes contains customary events of default, including, among others, (a) non-payment; (b) non-compliance with covenants (in some cases, subject to grace periods); (c) payment default under, or acceleration events affecting, material indebtedness and (d) bankruptcy or insolvency events involving us or certain of our subsidiaries. We were in compliance with all covenants as of December 31, 2021.

Debt Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any 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 the hedging requirements of the 2021 RBL Facility, 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 two years. We have also entered into Utah 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.

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

For our purchased oil puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For most 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, 2021 we have net payable deferred premiums of approximately $21 million, which is reflected in the mark-to-market valuation and will be payable beginning in 2022 through 2024, in approximately the same amount each year.

For our put spreads, in addition to any deferred premium payments, we would receive settlement payments for prices below the indicated highest price of the long put with the maximum payment received per barrel equal to the difference between the indicated prices of the long and short put. No payment would be made or received for prices above the highest indicated price of the long put. The short put spreads offset the long put spreads.

For our sold oil and gas puts, we would make settlement payments for prices below the indicated weighted-average price. No payment would be due for prices above the indicated weighted-average price.

For our sold oil and gas calls, we would make settlement payments for prices above the indicated weighted-average price. No payment would be due for prices below the indicated weighted-average price.

For our purchased gas puts, we would receive settlement payments for prices below the indicated weighted-average price. No payment would be received for prices above the indicated weighted-average price.

For our purchased gas calls, we would receive settlement payments for prices above the indicated weighted-average price. No payment would be received for prices below the indicated weighted-average price.

We use oil and gas swaps and puts to protect our sales against decreases in oil and gas prices. We also use swaps to protect our natural gas purchases against increases in prices. We do not enter into derivative contracts for speculative trading purposes and have not accounted for our derivatives as cash-flow or fair-value hedges. The changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil and gas sales hedges are classified in the revenues and other section of the statement of operations, while natural gas purchase hedges are included in expenses and other section of the statement of operations.

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As of December 31, 2021, we had the following crude oil production and gas purchases hedges.

	Q1 2022	Q2 2022	Q3 2022	Q4 2022	FY 2023	FY 2024
Brent						
Swaps						
Hedged volume (bbls)	796,500	753,500	736,000	736,000	1,595,750	732,000
Weighted-average price ($/bbl)	$ 67.02	$ 66.59	$ 66.36	$ 66.36	$ 65.26	$ 61.78
Put Spreads						
Long $50/$40 Put Spread hedged volume (bbls)	405,000	409,500	414,000	414,000	2,555,000	1,647,000
Short $50/$40 Put Spread hedged volume (bbls)	45,000	45,500	46,000	46,000	365,000	366,000
Collars						
Purchased Puts hedged volume (bbls)	270,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 40.00	$ —	$ —	$ —	$ —	$ —
Sold Calls hedged volume (bbls)	270,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 80.00	$ —	$ —	$ —	$ —	$ —
Henry Hub						
Purchased Puts						
Hedged volume (mmbtu)	1,800,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 2.75	$ —	$ —	$ —	$ —	$ —
Purchased Calls						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Sold Puts						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75

Our long put spread position ($50/$40) is presented in the table above on a gross basis as originally established. Subsequently, we have entered into additional transactions that exactly offset a portion of the original long put spread position and these are shown as short put spread ($50/$40).

In 2022 we added sold fixed price oil swaps (Brent) of 2,000 bbl/d at $80.40 beginning February 2022 through December 2022, 2,000 bbl/d at $85.20 beginning March 2022 through December 2022, and 4,000 bbl/d at $78.42 beginning January 2023 through December 2023. We also added Brent collars of 3,000 bbl/d for calendar year 2023 buying $40.00 put options and selling $106.33 call options.

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, 2021 and 2020.The following tables present the fair values (gross and net) of our outstanding derivatives as of December 31, 2021 and 2020.

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	December 31, 2021			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 5,360	$ (5,360)	$ —
Commodity Contracts	Non-current assets	29,828	(28,758)	1,070
Liabilities:				
Commodity Contracts	Current liabilities	(34,985)	5,360	(29,625)
Commodity Contracts	Non-current liabilities	(47,335)	28,758	(18,577)
Total derivatives		$ (47,132)	$ —	$ (47,132)

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

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

We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our 2021 RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A or A2 credit rating or better from Standards & Poor’s or Moody’s, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which partially mitigates the counterparty nonperformance risk.

(Losses) Gains on Derivatives

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

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
(Losses) gains on oil and gas sales derivatives	$ (156,399)	$ 117,781	$ (37,998)
Gains (losses) on natural gas purchase derivatives	38,577	(1,035)	(6,957)
Total (losses) gains on derivatives	$ (117,822)	$ 116,746	$ (44,955)

For the year ended December 31, 2021, we paid net cash settlements of approximately $92 million. For the years ended December 31, 2020 and 2019 we received net cash scheduled settlements of approximately $142 million and $42 million respectively.

Note 5—Commitments and Contingencies

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

We accrue for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at December 31, 2021 and December 31, 2020. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of accruals on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our 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, 2021, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We settled the lawsuit and the case was dismissed with prejudice on February 1, 2022, which also satisfied the road obligation.

Securities Litigation Matter

On November, 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, 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 January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the 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 of 1933 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; plaintiffs' opposition is due on March 21, 2022 and Defendants' reply is due on May 16, 2022.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Other Commitments

We entered into certain firm commitments to secure transportation of our production and third-party natural gas to market as well as processing which require a minimum monthly charge regardless of whether the contracted capacity is used or not. We also entered into a drilling commitment associated with our property acquisition. We also have operating lease agreements mainly for office space. Office rent payments are generally expensed as part of general and administrative expenses and were approximately $2.0 million, $1.5 million and $1.5 million in 2021, 2020 and 2019, respectively.

At December 31, 2021, future net minimum payments for non-cancelable purchase obligations and operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes and insurance and maintenance expense) were as follows:

	2022	2023	2024	2025	2026	Thereafter	Total
				(in thousands)			
Processing and transportation contracts[1]	$ 9,835	$ 10,348	$ 9,130	$ 8,083	$ 8,082	$ 51,604	$ 97,082
Operating lease obligations	2,279	2,122	1,649	1,551	1,554	936	10,091
Other purchase obligations[2]	20,700	2,400	—	—	—	—	23,100
Total	$ 32,814	$ 14,870	$ 10,779	$ 9,634	$ 9,636	$ 52,540	$ 130,273

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

(2) Amounts included a purchase commitment of $6 million to build a road, which was classified as current. In January 2022 the purchase commitment of $6 million was fully resolved without any payment. Additionally, we have a drilling commitment in California, for which we are required to drill 57 wells with an estimated cost and minimum commitment of $17.1 million by April 2023. 49 of those wells are estimated at $14.7 million and are required to be drilled by December 2022.

Note 6—Stockholders' Equity

Cash Dividends

Our Board of Directors approved regular cash dividends on our common stock of $0.04 per share for each of the first and second quarters of 2021 and $0.06 per share for each of the third and fourth quarters of 2021. For the year ended December 31, 2021 we paid approximately $11 million in cash dividends on our common stock. For the year ended December 31, 2020 we paid approximately $19 million in cash dividends on our common stock, which included payment of the dividend declared for the fourth quarter of 2019 and a $0.12 per share cash dividend for the first quarter of 2020. For the year ended December 31, 2019 we declared a cash dividend of $0.12 per share each quarter for a total of $0.48 per share and paid approximately $39 million in cash dividends on our common stock.

Our Board of Directors declared a regular dividend for the first quarter of 2022 at a rate of $0.06 per share on the Company's outstanding common stock, payable on April 15, 2022 to shareholders of record at the close of business on March 15, 2022.

Common Stock

On February 28, 2017 (the “Effective Date”), 32,920,000 shares of common stock in Berry Corp. were distributed in accordance with our plan of reorganization in the Chapter 11 Proceeding (the “Plan”). In addition 7,080,000 shares of Berry Corp. common stock reserved for future issuance in the event that the holders of such rights chose cash distributions instead. We negotiated with the claimants to settle their claims and in 2019 we issued approximately 2,770,000 shares of Berry Corp. common stock instead of 7,080,000 to resolve these claims for approximately $20 million.

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 (the “Board”) 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 the Effective Date, Berry Corp. entered into a registration rights agreement (the “Registration Rights Agreement”) with certain holders of the Unsecured Notes. Subsequently, the registration rights agreement was amended and restated in connection with our IPO.

In accordance with the Registration Rights Agreement, Berry Corp. filed a shelf registration statement with the SEC subsequent to the Effective Date. 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 issued or to be issued by Berry Corp. under the Plan (defined in Note 13), (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, 2021, there were 80,007,149 shares of common stock outstanding. Up to an additional 6,998,815 shares were issuable for unvested restricted stock units and performance restricted stock units (assuming maximum achievement of performance goals) under the Company's 2017 Omnibus Incentive Plan as of December 31, 2021.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board’s evaluation of market conditions for our common stock at the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the year ended

December 31, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million in the third quarter. All shares repurchased are reflected as treasury stock. Accordingly, as of December 31, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

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) awards with a market objective measured against both absolute total stockholder return (“Absolute TSR”) and a relative total stockholder return (“Relative TSR”) (the “TSR PSUs”) over the performance period and (ii) awards based on the Company's average cash returned on invested capital (“CROIC PSUs”) over the performance period. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 250% of the TSR PSUs granted in 2021, 0% to 200% of the TSR PSUs granted in prior years and from 0% to 200% of the CROIC PSUs granted in 2021. No CROIC PSUs were granted prior to 2021.

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

On June 27, 2018, our board of directors adopted the second amended and restated 2017 Omnibus Incentive Plan (“Omnibus Plan”), as amended and restated (our “Restated Incentive Plan”). This plan constitutes an amendment and restatement of the plan (the “Prior Plan”) as in effect immediately prior to the adoption of the Restated Incentive Plan. The Prior Plan constituted an amendment and restatement of the plan originally adopted as of June 15, 2017 (the “2017 Plan”). The Restated Incentive Plan provides for the grant, from time to time, at the discretion of the board of directors or a committee thereof, of stock options, stock appreciation rights (“SARs”), restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards and substitute awards. The maximum number of shares of common stock that may be issued pursuant to an award under the Restated Incentive Plan is 10,000,000 inclusive of the number of shares of common stock previously issued pursuant to awards granted under the Prior Plan or the 2017 Plan. The maximum number of shares remaining that may be issued is 1,368,778 as of December 31, 2021.

For the years ended December 31, 2021, 2020, and 2019 the stock-based compensation expense was approximately $14 million, $15 million, and $9 million, respectively. For the years ended December 31, 2021, 2020 and 2019 the stock-based compensation the income tax benefit was not material.

The table below summarizes the activity relating to RSUs issued under the Restated Incentive Plan during the year ended December 31, 2021. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at December 31, 2021 was approximately $8 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, 2020	1,939	$ 7.52
Granted	1,833	$ 4.65
Vested	(774)	$ 7.97
Forfeited	(418)	$ 5.54
Non-vested at December 31, 2021	2,580	$ 5.67

The table below summarizes the activity relating to the PSUs issued under the Revised Incentive Plan during the year ended December 31, 2021. Unrecognized compensation cost associated with the PSUs at December 31, 2021 is approximately $10 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, 2020	1,652	$ 14.77
Granted	998	$ 5.96
Vested	(75)	$ 12.75
Forfeited	(490)	$ 13.17
Non-vested at December 31, 2021	2,085	$ 11.00

Note 7—Defined Contribution Plan

We sponsor a defined contribution retirement 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. The 401(k) plan provided for a matching contribution of up to 6% of an employee’s eligible compensation until June 2020. The Company temporarily suspended matching due to COVID-19. 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 $1.6 million, $1.0 million, and $1.7 million for the years ended December 31, 2021, 2020, and 2019, respectively, under the provisions of the 401(k) plan.

Note 8—Income taxes

The change in our effective rate from 2.8% in the year ended December 31, 2020 to (10.0)% for the year ended December 31, 2021 is primarily due to nondeductible stock compensation, adjustments to our tax credit carryforward balances, and changes in the valuation allowance. The key contributor to the change in our effective rate from (523)% in the year ended December 31, 2019 to 2.8% for the year ended December 31, 2020 is due to the valuation allowance recorded in 2020 and the recognition of U.S. federal general business credits in 2019 related to the 2017 and 2018 tax periods.

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

Income tax expense (benefit) consisted of the following:

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
Current taxes:			
Federal	$ —	$ —	$ —
State	581	828	227
Total current taxes	581	828	227
Deferred taxes:			
Federal	832	2,653	(36,756)
State	—	(10,699)	(21)
Total deferred taxes	832	(8,046)	(36,777)
Total current and deferred taxes	$ 1,413	$ (7,218)	$ (36,550)

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

	Year Ended December 31,		
	2021	2020	2019
Federal statutory rate	21.0 %	21.0 %	21.0 %
State, net of federal tax benefit	3.7 %	6.3 %	8.9 %
Nondeductible compensation	(24.5)%	— %	— %
Effect of permanent differences	(4.7)%	(0.6)%	0.2 %
Tax credits - Prior Year	(29.5)%	4.9 %	(546.4)%
Tax credits - Current Year	21.5 %	1.1 %	— %
State return to provision	(0.2)%	(1.1)%	(6.6)%
Change in valuation allowance	2.7 %	(28.8)%	0.0 %
Effective tax rate	(10.0)%	2.8 %	(522.9)%

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

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

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 40,846	$ 21,205
Accruals	11,731	14,208
Asset retirement obligations	44,437	43,518
Derivative instruments	12,776	5,654
Tax credits	61,044	62,058
Other	3,551	4,946
Subtotal	174,385	151,589
Valuation allowance	(77,546)	(77,923)
Total deferred tax assets	96,839	73,666
Deferred tax liabilities:		
Book tax differences in property basis	(98,670)	(74,677)
Total deferred tax liabilities	(98,670)	(74,677)
Net deferred tax liability	$ (1,831)	$ (1,011)

As of December 31, 2021, the Company had approximately $181 million of federal net operating loss ("NOL") carryforwards and $49 million of state NOL carryforwards. The vast majority of 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 ended 2027. In addition, as of December 31, 2021, the Company had US federal general business tax credit carryforwards totaling $54 million and state tax credits of $9 million ($7 million net of federal benefit), which, if unused, will 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 consider the scheduled reversal of deferred income tax liabilities and projected future income for this determination. Due to the history of losses in recent years, management continues to believe that it is more likely than not that a large portion of our deferred tax assets would not be realized. Accordingly, we recorded a valuation allowance on our deferred tax assets for the years ended December 31, 2021 and 2020 in the amount of $78 million.

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(in thousands)	
Unrecognized tax benefits - January 1	$ —	$ 13,892
Prior year - change	—	(13,892)
Current year - change	—	—
Unrecognized tax benefits - December 31	$ —	$ —

During the third quarter 2020, the Internal Revenue Service issued final regulations implementing interest expense deduction limitation rules under section 163(j) of the Internal Revenue Code. The final regulations changed certain rules on the computation and limitation of interest expense amounts and are applicable for tax years beginning on or after November 13, 2020. Early adoption is permitted for tax years beginning after December 31, 2017. We assessed the impact of these regulations being issued in 2020. As a result, we recognized the entirety of its

$14 million of uncertain tax benefits that were recorded as of December 31, 2019. The recognition of these uncertain tax benefits did not affect the effective tax rate. No penalties or interest expense have been accrued on unrecognized tax benefits in the periods presented.

We had no material uncertain tax positions at December 31, 2021 or 2020. 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 2018 thru 2021 federal and 2017 thru 2021 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:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Prepaid expenses	$ 26,840	$ 3,580
Materials and supplies	9,533	11,666
Prepaid deposits	6,415	12
Oil inventories	2,933	3,490
Other	225	652
Total other current assets	$ 45,946	$ 19,400

Other non-current assets at December 31, 2021 and December 31, 2020 included approximately $5 million and $7 million of deferred financing costs, net of amortization, respectively. During the year ended December 31, 2021 the allowance for doubtful accounts decreased by approximately $1.3 million, which represented collection of past due amounts and the reversal of that portion of the allowance to the consolidated statements of operations.

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

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

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Accounts payable - trade	$ 17,699	$ 11,055
Accrued expenses	62,962	43,452
Royalties payable	24,816	15,150
Greenhouse gas liability - current portion	7,513	35,554
Taxes other than income tax liability	8,273	10,118
Accrued interest	10,736	10,783
Dividends payable	4,800	—
Asset retirement obligation - current portion	20,000	25,000
Other	725	873
Total accounts payable and accrued expenses	$ 157,524	$ 151,985

At December 31, 2021 other non-current liabilities included approximately $18 million non-current greenhouse gas liability, which is due 2024. At December 31, 2020 we had no non-current greenhouse gas liability as the entire amount was due in 2021 and thus classified as a current liability in accounts payable and accrued expenses.

Supplemental Information on the Statement of Operations

For the years ended December 31, 2021, 2020, and 2019 other operating expenses were $3 million, $6 million, and $5 million respectively. 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 of gain on the sale of properties and over $2 million of income from employee retention credits. For the year ended December 31, 2020, other operating expenses included of $3 million of excess abandonment costs, $2 million of oil tank storage fees, and $1 million of drilling rig standby charges. For the year ended December 31, 2019 other operating income was $5 million, which mainly consisted of the costs in excess of the liability, due to earlier than anticipated abandonment and spending, related to our long-term abandonment activities and obligation.

Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
Supplemental Disclosures of Significant Non-Cash Operating Activities:			
Greenhouse gas liability - reclassification from long-term to current liability	$ —	$ 33,376	$ —
Supplemental Disclosures of Significant Non-Cash Investing Activities:			
Material inventory transfers to oil and natural gas properties	$ 3,424	$ 1,596	$ 10,056
Supplemental Disclosures of Cash Payments (Receipts):			
Interest, net of amounts capitalized	$ 29,211	$ 29,962	$ 30,720
Income taxes payments (refunds)	$ 699	$ 222	$ (2)

Cash and cash equivalents consists primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value. As part of our cash management system, we use a controlled disbursement account to fund cash distribution checks presented for payment by the holder. Checks issued but not yet presented to banks may result in overdraft balances for accounting purposes, and if so, are included in accounts payable and accrued expenses in the consolidated balance sheets. Such amounts are immaterial as of December 31, 2021 and December 31, 2020.

Note 10—Acquisitions and Divestitures

2021

C&J Well Services Acquisition

On October 1, 2021, we acquired one of the largest well servicing and abandonment business 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 Company's preliminary allocation of the purchase price, including preliminary working capital adjustments, to the estimated fair value of the CJWS net assets is as follows:

		October 1, 2021
		(in thousands)
Accounts receivable	$	17,254
Property and equipment		45,099
Other assets		1,700
Total assets acquired	$	64,053
Accounts payable and accrued expenses assumed		(10,927)
Net assets acquired	$	53,126

The allocation of the purchase price to C&J Well Services net tangible assets and liabilities as of October 1, 2021, is preliminary and subject to revisions to the fair value calculations for the identifiable assets and liabilities. The final purchase price allocation could differ from the preliminary allocation noted in the summary above. The acquired property and equipment is stated at fair value, and depreciation on the acquired property and equipment is computed using the straight-line method over the estimated useful lives of each asset.

The unaudited pro forma information presented below has been prepared to give effect to the C&J Well Services 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 C&J Well Services 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		2020	
	(unaudited) (in thousands)			
Revenue	$	664,549	$	657,796
Net income (loss)	$	740	$	(250,884)

Placerita Divestiture

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

2020

In May 2020, we acquired approximately 740 net acres in the North Midway Sunset Field for approximately $5 million. We paid $2 million at closing and the remaining $3 million was paid following our first production from this property, in the fourth quarter 2020. This property is adjacent to, and extends, our existing producing area and we have identified numerous future drilling locations. We believe additional opportunities exist in other productive reservoirs of this property. We also acquired all existing idle wells on this property, some of which we plan to return to production in the near future as price and strategy dictate. We will plug and abandon the remaining idle wells pursuant to our California idle well management plan. We recorded a $6 million liability for asset retirement obligations of the existing wells on this property.

We also acquired approximately 267 acres in McKittrick Field which will allow us to continue development of the 21Z mineral fee and leases without requiring written approval from a third party surface fee owner for infrastructure on or across the surface fee property. The purchase price was not material.

2019

During 2019 we had various property acquisitions of approximately $2.9 million that individually were not significant.

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. No incremental RSU or PSU shares were included in the diluted EPS calculation as their effect was anti-dilutive under the “if-converted” method for the years ended December 31, 2021 and 2020. The incremental RSU and PSU shares of 572,000 for the year ended December 31, 2019 were included in the diluted EPS calculation as their effect was dilutive under the “if-converted” method.

	Year Ended December 31,		
	2021	2020	2019
	(in thousands except per share amounts)		
Basic EPS calculation			
Net (loss) income	$ (15,542)	$ (262,895)	$ 43,539
Weighted-average shares of common stock outstanding	80,209	79,802	81,379
Basic (loss) earnings per share	$ (0.19)	$ (3.29)	$ 0.54
Diluted EPS calculation			
Net (loss) income	$ (15,542)	$ (262,895)	$ 43,539
Weighted-average shares of common stock outstanding	80,209	79,802	81,379
Dilutive effect of potentially dilutive securities[1]	—	—	572
Weighted-average common shares outstanding - diluted	80,209	79,802	81,951
Diluted (loss) earnings per share	$ (0.19)	$ (3.29)	$ 0.53

(1) We excluded 3.3 million and 0.1 million of combined RSUs and PSUs from the diluted weighted-average common shares outstanding because their effect was anti-dilutive for the years ended December 31, 2021 and 2020, respectively.

Note 12—Revenue Recognition

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

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

We derive revenue from sales of oil, natural gas and natural gas liquids ("NGL"), with the remaining revenue generated from sales of electricity and marketing activities. Effective October 1, 2021, we completed the acquisition of CJWS, a well servicing and abandonment business. 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). Our contracts with customers typically require payment within 30 days following invoicing.

Service Revenue

We recognize service revenue from the upstream 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 typically require payment within 30-60 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 majority of the portion sold from certain of 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.

Disaggregated Revenue

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

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
Oil sales	$ 587,613	$ 362,976	$ 543,634
Natural gas sales	32,679	14,041	19,391
Natural gas liquids sales	5,183	1,646	2,571
Service revenue	35,840	—	—
Electricity sales	35,636	25,813	29,397
Marketing revenues	3,921	1,426	2,094
Other revenues	477	150	316
Revenues from contracts with customers	701,349	406,052	597,403
(Losses) gains on oil and gas sales derivatives	(156,399)	117,781	(37,998)
Total revenues and other	$ 544,950	$ 523,833	$ 559,405

Note 13—Segment Information

As of October 1, 2021, we have operated in two business segments: (i) development and production (ii) well servicing and abandonment. The development and production segment is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah. On October 1, 2021, we completed the acquisition of an upstream well servicing and abandonment businesses in California, which became a reportable segment (wells servicing and abandonment) under U.S. GAAP. Prior to October 1, 2021, we did not have more than one reportable segment, thus no prior period segment information has been presented.

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, 2021			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues - excluding hedges	$ 665,509	$ 35,840	$ —	$ 701,349
Net income (loss) before income taxes	$ 82,826	$ 1	$ (96,956)	$ (14,129)
Adjusted EBITDA	$ 251,146	$ 4,310	$ (43,310)	$ 212,146
Capital expenditures	$ 129,479	$ 1,029	$ 2,211	$ 132,719
Total assets	$ 1,450,157	$ 81,093	$ (74,771)	$ 1,456,479

Adjusted EBITDA is the measure reported to the chief operating decision maker (CODM) for purposes of making decisions about allocating resources to and assessing performance of each segment. Adjusted EBITDA is calculated 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.

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

	Year Ended December 31, 2021			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 82,825	$ 1	$ (98,368)	$ (15,542)
Add (Subtract):				
Interest expense	—	—	31,964	31,964
Income tax expense	—	—	1,413	1,413
Depreciation, depletion, and amortization	136,915	2,974	4,606	144,495
Losses on derivatives	117,822	—	—	117,822
Net cash paid for scheduled derivative settlements	(87,625)	—	—	(87,625)
Other operating expenses	109	—	2,992	3,101
Stock compensation expense	1,100	—	12,683	13,783
Non-recurring costs	—	1,335	1,400	2,735
Adjusted EBITDA	$ 251,146	$ 4,310	$ (43,310)	$ 212,146

Note 14—Subsequent Events

Piceance Divestiture

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 no material impact to the financial statements.

Antelope Creek Acquisition

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 700 boe/d.

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,		
	2021	2020	2019
	(in thousands)		
Property acquisition costs:			
Proved[1]	$ 1,256	$ 11,597	$ 5,382
Unproved	—	—	—
Exploration costs	—	—	—
Development costs[2]	153,821	96,971	277,511
Total costs incurred	$ 155,077	$ 108,568	$ 282,893

(1) Included in proved property acquisition costs for the year ended December 31, 2021, 2020 and 2019 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $0.4 million, $5.7 million and $2.4 million, respectively.

(2) Included in development costs for the year ended December 31, 2021, 2020 and 2019 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $32.5 million, $10.2 million and $65.7 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,	
	2021	2020
	(in thousands)	
Proved properties	$ 1,308,378	$ 1,181,865
Unproved properties	291,514	311,195
Total proved and unproved properties	1,599,892	1,493,060
Less accumulated depreciation, depletion and amortization	(356,509)	(252,325)
Net capitalized costs	$ 1,243,383	$ 1,240,735

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

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, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in thousands)		
Net revenues from production:			
Oil, natural gas and NGL sales	$ 625,475	$ 378,663	$ 565,596
Electricity sales	35,636	25,813	29,397
Other production-related revenue	4,245	1,431	2,258
Total net revenues from production[(1)]	665,356	405,907	597,251
Operating costs for production:			
Lease operating expenses	236,048	186,348	216,294
Electricity generation expenses	23,148	16,608	19,490
Transportation expenses	6,897	6,938	8,059
Production-related general and administrative expenses	1,338	1,766	2,735
Taxes, other than income taxes	46,278	34,987	40,254
Other production-related costs	3,811	1,380	2,073
Total operating costs for production	317,520	248,027	288,905
Other costs:			
Depreciation, depletion and amortization	137,991	135,361	101,816
Impairment of long-lived assets	—	289,085	51,081
Other operating expenses	2,353	5,673	4,545
Total other costs	140,344	430,119	157,442
Pretax income (loss)	207,492	(272,239)	150,904
Income tax expense (benefit)	57,117	(83,467)	10,084
Results of operations	$ 150,375	$ (188,772)	$ 140,820

(1) Excludes cash paid for derivative settlements of $92 million for the year ended December 31, 2021 and excludes cash received for scheduled derivative settlements of $142 million and $42 million for the years ended December 31, 2020 and 2019.

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, which include DD&A allowances, after giving effect to permanent differences. See Note 8 for additional information about income taxes.

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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, 2021, 2020 and 2019 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, 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

	Year Ended December 31, 2020			
	Oil mbbls	NGLs mbbls	Natural Gas mmcf	Total mboe
Total proved reserves:				
Beginning of year	129,773	1,180	44,815	138,422
Extensions and discoveries	733	—	—	733
Revisions of previous estimates	(31,494)	(307)	(12,352)	(33,860)
Purchases of minerals in place	104	—	—	104
Sales of minerals in place	—	—	—	—
Production	(9,181)	(131)	(6,864)	(10,456)
End of year	89,935	742	25,599	94,943
Proved developed reserves:				
Beginning of year	74,102	1,054	39,063	81,667
End of year	51,249	742	25,599	56,257
Proved undeveloped reserves:				
Beginning of year	55,670	127	5,752	56,756
End of year	38,686	—	—	38,686

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

	Year Ended December 31, 2019			
	Oil mbbls	NGLs mbbls	Natural Gas mmcf	Total mboe
Total proved reserves:				
Beginning of year	114,765	1,147	160,849	142,720
Extensions and discoveries	13,321	—	—	13,321
Revisions of previous estimates	10,759	160	(109,323)	(7,302)
Purchases of minerals in place	159	24	701	300
Sales of minerals in place	—	—	—	—
Production	(9,231)	(151)	(7,412)	(10,617)
End of year	129,773	1,180	44,815	138,422
Proved developed reserves:				
Beginning of year	73,203	1,047	76,331	86,971
End of year	74,102	1,054	39,063	81,667
Proved undeveloped reserves:				
Beginning of year	41,562	100	84,518	55,749
End of year	55,670	127	5,752	56,756

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 increased by approximately 2 mmboe to approximately 97 mmboe for the year ended December 31, 2021. The year ended December 31, 2021, includes 9 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 1 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 3 mmboe to proved reserves.

Proved reserves decreased by approximately 43 mmboe to approximately 95 mmboe for the year ended December 31, 2020. The year ended December 31, 2020, includes 34 mmboe of negative revisions of previous estimates. Price-driven revisions were 31 mmboe, 91% of total revisions, and were due to the dramatic decline in commodity prices experienced in 2020. Performance revisions were a decrease of 3 mmboe, 9% of total revisions. Extensions and discoveries, exclusively in our California properties, added 1 mmboe to proved reserves. Negative performance revisions as well as modest increases to extensions and discoveries were the result of very limited development capital investment in 2020 which was necessitated by market conditions created by the COVID-19 pandemic and exacerbated by OPEC+'s dispute over production cuts.

Proved reserves decreased by approximately 4 mmboe to approximately 138 mmboe for the year ended December 31, 2019. Extensions and discoveries, principally in our California properties, contributed 13 mmboe to the overall change in proved reserves. These extensions included McKittrick steamflood expansions based on delineation wells drilled in 2019, Homebase Pliocene development, as well as expansion of our thermal Diatomite operations. The year ended December 31, 2019, includes 7 mmboe of negative revisions of previous estimates. Negative revisions due to price were 7 mmboe and this was caused by the current commodity price environment. Performance revisions included a decrease of 14 mmboe due to the impairment of our Piceance gas properties and the removal of the proved undeveloped reserves related to this impairment. However, there were positive technical

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

revisions of 13 mmboe primarily related to the improved base performance and redevelopment in our thermal Diatomite area.

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 for additional information about income taxes.

	Year Ended December 31,		
	2021	2020	2019
	(in thousands, except for prices)		
Future cash inflows	$ 5,879,599	$ 3,657,907	$ 7,788,647
Future production costs	(2,589,043)	(2,091,021)	(3,623,688)
Future development costs[1]	(808,295)	(830,028)	(1,106,333)
Future income tax expenses[2]	(484,358)	(1,646)	(587,487)
Future net cash flows	1,997,903	735,212	2,471,139
10% annual discount for estimated timing of cash flows	(764,632)	(219,033)	(1,005,002)
Standardized measure of discounted future net cash flows	$ 1,233,271	$ 516,179	$ 1,466,137
Representative prices:[3]			
Brent Oil (bbl)	$ 69.47	$ 41.77	$ 63.15
Henry Hub Natural gas (mmbtu)	$ 3.64	$ 2.03	$ 2.62

(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.

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

The following table summarizes the changes in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
Standardized measure—beginning of year	$ 516,179	$ 1,466,137	$ 1,761,546
Net change in sales and transfer prices and production costs related to future production	1,140,342	(1,135,565)	(309,347)
Changes in estimated future development costs	8,215	198,009	(120,688)
Sales and transfers of oil, natural gas and NGLs produced during the period	(336,031)	(149,806)	(300,261)
Net change due to extensions, discoveries and improved recovery	56,504	11,621	180,825
Purchase of minerals in place	830	1,668	2,649
Sales of minerals in place	(5)	—	—
Net change due to revisions in quantity estimates	217,921	(329,680)	(124,110)
Previously estimated development costs incurred during the period	48,488	2,762	116,921
Accretion of discount	52,015	180,673	215,153
Changes in production rates and other	(195,093)	(69,293)	(5,939)
Net change in income taxes	(276,094)	339,653	49,388
Net increase (decrease)	717,092	(949,958)	(295,409)
Standardized measure—end of year	$ 1,233,271	$ 516,179	$ 1,466,137

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,		
	2021	2020	2019
Weighted-average realized prices:			
Oil without hedges (bbl)	$ 66.57	$ 39.56	$ 58.93
Natural gas ($/mcf)	$ 5.27	$ 2.08	$ 2.66
NGLs ($/bbl)	$ 36.64	$ 12.57	$ 17.02
Production costs (per boe):			
Lease operating expenses	$ 23.60	$ 17.86	$ 20.42

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 President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2021. 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, 2021 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, 2021, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2021.

Management’s report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only management’s report in this Annual Report on Form 10-K. Therefore, this Annual Report on Form 10-K does not include such an attestation.

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. Except as described below, there has been no change in Berry’s internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) during the fourth quarter of 2021 that has materially affected, or is reasonably likely to materially affect, Berry’s internal control over financial reporting.

In the fourth quarter of 2021, Berry acquired C&J Well Services and implemented a new Enterprise Resource Planning (ERP) system for that subsidiary following the acquisition, resulting in modifications to C&J Well Services historical internal controls over financial reporting.

Item 9B. Other Information

None

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 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2021.

Our board of directors has adopted a code of business 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 business conduct by posting such information 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 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2021.

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 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2021. See also Part II—Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Securities Authorized for Issuance Under Equity Compensation Plans.

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 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2021.

Item 14. Principal Accounting Fees and Services

Our independent registered public accounting firm is KPMG LLP, Los Angeles, CA, Auditor Firm ID: 185.

The information required by this Item 14 is incorporated herein by reference to our definitive Proxy Statement, for the 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2021.

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	Third Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.2 of Form 8-K filed February 19, 2020)
3.3	Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.4	Certificate of Amendment to Certificate of Designation (incorporated by reference to Exhibit 3.1 of Form 8-K filed July 30, 2018)
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, Berry Petroleum Corporation and Wells Fargo Bank, N.A., 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	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	Assignment Agreement, dated February 28, 2017, between Linn Acquisition Company, LLC and Berry Petroleum Corporation (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.2	Transition Services and Separation Agreement, dated February 28, 2017, by and among Berry Petroleum Company, LLC, Linn Energy, LLC and certain of its affiliates and subsidiaries (incorporated by reference to Exhibit 10.2 to the Company's Annual Report on Form 10-K filed March 8, 2019)
10.3	Amended and Restated Stockholders Agreement between Berry Petroleum Corporation and certain holders party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed July 30, 2018)
10.4	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))
10.5†	Second Amended and Restated Executive Employment Agreement, dated March 1, 2020, between Berry Petroleum Company, LLC and Arthur "Trem" Smith (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K filed February 27, 2020)

Exhibit Number	Description
10.6†	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)
10.7†	Amended and Restated Executive Employment Agreement by and between Berry Petroleum Company, LLC and Danielle Hunter, effective March 1, 2020 (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed February 24, 2021)
10.8†	Employment Agreement by and between Berry Petroleum Company, LLC and Fernando Araujo, effective August 14, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed August 20, 2020)
10.9†	Second Amended and Restated Executive Employment Agreement by and between Berry Petroleum Company, LLC and Gary A. Grove, effective March 1, 2020 (incorporated by reference to Exhibit 10.2 of Form 8-K filed March 30, 2020)
10.10†	Transition and Separation Agreement and General Release of Claims entered into effective July 31, 2020 by and between Gary A. Grove and Berry Petroleum Company, LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed August 5, 2020)
10.11†	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))
10.12†	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))
10.13†	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))
10.14†	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))
10.15†	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)
10.16†	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)
10.17†	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))
10.18†	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))
10.19†	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)
10.20†	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)

Exhibit Number	Description
10.21†	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)
10.22†	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)
10.23†	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)
10.24	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))
10.25	Stock Purchase Agreement by and between Berry Petroleum Corporation, Oaktree Value Opportunities Fund Holdings, L.P. and Oaktree Opportunities X Fund Holdings (Delaware), L.P. dated July 17, 2018 (incorporated by reference to Exhibit 10.2 of Form 8-K filed July 30, 2018)
10.26	Stock Purchase Agreement by and between Berry Petroleum Corporation and certain funds affiliated with Benefit Street Partners named in Schedule I thereto, dated July 17, 2018 (incorporated by reference to Exhibit 10.3 of Form 8-K filed July 30, 2018)
10.27	Credit Agreement, dated August 26, 2021, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, and certain lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed August 27, 2021)
10.28	First Amendment to Credit Agreement, dated December 8, 2021, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, and certain lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 10, 2021)
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
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.
99.1*	Report as of December 31, 2021 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.
(†) Indicates a management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

Not applicable.

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:

"AROs" means asset retirement obligations.

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

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

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

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

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

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

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

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

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

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

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

"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.

"*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.

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

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

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

"*Differential*" means an adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*ICE*" means Intercontinental Exchange.

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

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

"*IOR*" means improved oil recovery.

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

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

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

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

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

"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.

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

"*MW*" means megawatt.

"*MWHs*" means megawatt hours.

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

"*NASDAQ*" means Nasdaq Global Select Market.

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

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

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

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

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

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

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

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

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

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

"*OTC*" means over-the-counter

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*QF*" means qualifying facility.

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

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

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

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

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

"*Reserves*" means estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

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

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

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

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

"SARs" is an abbreviation for stock appreciation rights.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*WTI*" means West Texas Intermediate.

SIGNATURES

Pursuant to the requirements of 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 4, 2022	/s/ A. T. Smith
		A. T. "Trem" Smith
		President and 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 4, 2022	/s/ A. T. Smith A. T. "Trem" Smith	President and Chief Executive Officer, and Director (Principal Executive Officer)
March 4, 2022	/s/ Cary Baetz Cary Baetz	Executive Vice President and Chief Financial Officer, and Director (Principal Financial Officer)
March 4, 2022	/s/ M. S. Helm Michael S. Helm	Chief Accounting Officer (Principal Accounting Officer)
March 4, 2022	/s/ Brent S. Buckley Brent S. Buckley	Director
March 4, 2022	/s/ Renée Hornbaker Renée Hornbaker	Director
March 4, 2022	/s/ Anne L. Mariucci Anne L. Mariucci	Director
March 4, 2022	/s/ Donald L. Paul Donald L. Paul	Director

Exhibit 21.1

Subsidiaries of Berry Corporation (bry)

Entity Name	Jurisdiction
Berry Petroleum Company, LLC	Delaware
C&J Well Services, LLC	Delaware
CJ Berry Well Services Management, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (Nos. 333-233207 and 333-226582) on Forms S-3 and S-8 of our report dated March 4, 2022, with respect to the consolidated financial statements of Berry Corporation (bry).

/s/ KPMG LLP

Los Angeles, California
March 4, 2022

Exhibit 23.2

March 4, 2022

Berry Corporation (bry)
16000 N. Dallas Parkway, Suite 500
Dallas, Texas 75248

Ladies and Gentlemen:

We hereby consent to (i) the use of the name DeGolyer and MacNaughton, (ii) references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, and (iii) the use of information from, and the inclusion of, our report of third party dated January 19, 2022, containing our opinion of the proved reserves and future net revenue, as of December 31, 2021, of Berry Corporation (bry) (our "Letter Report") (a) in the Berry Corporation (bry) Annual Report on Form 10-K for the year ended December 31, 2021 (the "10-K") and (b) by incorporation by reference into (1) the Form S-3 of Berry Petroleum Corporation (File No. 333-233207) and (2) the Form S-8 of Berry Petroleum Corporation (File No. 333-226582). We further consent to the inclusion of our Letter Report as an exhibit to the 10-K and through incorporation by reference in the Plan Registration Statement. We further consent to the reference to DeGolyer and MacNaughton under the heading "EXPERTS" in the related prospectus.

Very truly yours,

\s\ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

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

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

1. I have reviewed this Annual Report on Form 10-K of Berry Corporation (bry) (the "registrant");

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

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

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

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

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

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

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

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 4, 2022

/s/ A. T. Smith

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

Exhibit 31.2

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

I, Cary Baetz, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berry Corporation (bry) (the “registrant”);

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

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

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

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

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

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

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

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 4, 2022

/s/ Cary Baetz

Cary Baetz

Executive Vice President and
Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of Berry Corporation (bry) (the "Company") for the year ended December 31, 2021, as filed with the Securities and Exchange Commission on March 4, 2022, A. T. "Trem" Smith, as President and Chief Executive Officer of the Company, and Cary Baetz, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of our knowledge that:

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

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 4, 2022

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

Date: March 4, 2022

/s/ Cary Baetz
Cary Baetz
Executive Vice President and
Chief Financial Officer

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

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

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

January 19, 2022

Berry Corporation (bry)
11117 River Run Blvd.
Bakersfield, CA 93311

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2021, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Berry Corporation (bry) (Berry) has represented it holds an interest. This evaluation was completed on January 19, 2022. The properties evaluated herein consist of working and royalty interests located in the States of California, Colorado, and Utah. Berry has represented that these properties account for 100 percent on a net equivalent barrel basis of Berry's net proved reserves as of December 31, 2021. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Berry.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Berry after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Berry to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Berry, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Berry and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Berry with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, 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.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for

development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be 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.

(ii) Undrilled locations can be classified as having 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable 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, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revised June 2019) Approved by the SPE Board on 25 June 2019.” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Berry, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Berry.

Berry has represented that its senior management is committed to the development plan provided by Berry and that Berry has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

The volumetric method was used to estimate the original oil in place (OOIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties. Most of the properties in California evaluated herein are produced using thermal recovery methods involving either cyclic steam injection or continuous steamflood operation. Therefore, steam-oil ratios and steam volumes were analyzed and projected and were used in the estimation of reserves when applicable.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Berry from wells drilled through December 31, 2021, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through September 2021. Estimated cumulative production, as of December 31, 2021, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the quantities are located. Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Berry, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Berry. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Berry has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. For Berry's evaluated properties in California, Berry supplied differentials to a Brent oil reference price of $69.47 per barrel and the prices were held constant thereafter. For Berry's evaluated properties in Colorado and Utah, Berry supplied differentials to a West Texas Intermediate oil reference price of $66.55 per barrel and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $65.10 per barrel of oil and condensate and $36.08 per barrel of NGL.

Gas Prices

Berry has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Berry provided differentials to the Henry Hub reference price of $3.64 per million Btu and the prices were held constant thereafter. Btu factors provided by Berry were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $3.981 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using rates provided by Berry, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Berry based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Berry and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2021 values, provided by Berry, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Berry for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

Certain abandonment costs for the developed properties were provided by Berry at the asset level. These abandonment costs have not been allocated to the various individual properties within each asset.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC;

provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2021, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2021			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	53,453	1,209	60,351	64,720
Proved Undeveloped	32,349	49	2,103	32,749
Total Proved	**85,802**	**1,258**	**62,454**	**97,469**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2021, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Total Proved (M$)
Future Gross Revenue	3,701,079	5,879,600
Production Taxes	68,935	89,132
Ad Valorem Taxes	105,100	167,481
Operating Expenses	1,631,561	2,332,430
Capital Costs	30,822	481,850
Abandonment Costs	284,650	326,446
Future Net Revenue	1,580,011	2,482,261
Present Worth at 10 Percent	1,038,814	1,513,338

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2021, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Berry. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Berry. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

\s\ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

\s\ Dilhan Ilk
Dilhan Ilk, P.E.
[SEAL] Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Berry Corporation (bry) dated January 19, 2022, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree from Texas A&M University in 2005, and a Doctor in Philosophy degree from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 11 years of experience in oil and gas reservoir studies and reserves evaluations.

\s\ Dilhan Ilk

[SEAL] Dilhan Ilk, P.E.

Senior Vice President

DeGolyer and MacNaughton