2020 ANNUAL REPORT

Preserving the foundation for future growth

BERRY CORPORATION

"One of bry's core financial tenets has always been to live out of Levered Free Cash Flow while protecting our base production. Even in the midst of an unprecedented year we successfully delivered on our plan."

Over the last year, bry faced new and evolving situations in the oil and gas market, proactively adapted operations in the midst of a pandemic, and continued to navigate the volatile political landscape of California. Relatively speaking, our challenges were not unique compared to others in the industry, but our 2020 performance and results were. One of bry's core financial tenets has always been to live out of Levered Free Cash Flow while protecting our base production. Even in the midst of an unprecedented year we successfully delivered on our plan.

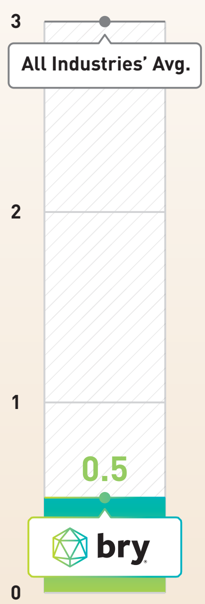
Early on in the year, we took aggressive action to improve our hedge position to allow us to sustain operations even in the worst pricing situation imaginable. We also took advantage of our agile drilling plans and worked proactively to keep our year-over-year production flat. We also developed and deployed a strategic cost savings plan designed to identify and trim 10% in sustainable year-over-year expenses. Our goal was not just to cut costs for short-term gain, but to improve efficiencies, upgrade talent, and reorganize functions for greater collaboration and efficacy for bry's long-term success.

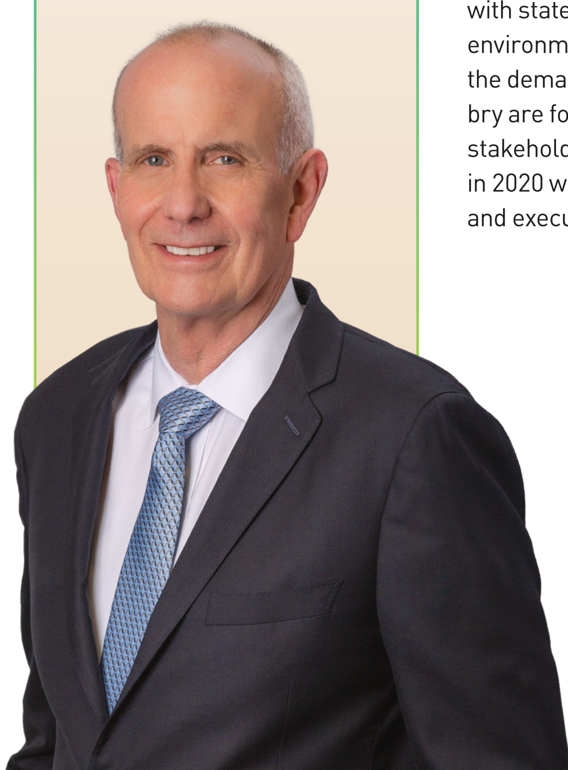
As the pandemic began to unfold in the United States, and particularly in California, we quickly adjusted our operations to allow office personnel to work from home, while still supporting essential workers in the field 24/7. The health, safety, and well-being of all of our employees is – and has always been – of paramount importance to us; 2020 only emphasized the significance of that commitment.

Even as much of the world halted activity and progress, we pushed forward to further evolve our culture and prepare for the future.

We achieved the best Safety Record to date.

In 2020 our Total Recordable Incident Rate, or TRIR, was 0.5, our lowest rate ever. This is well below the United States average for all industries, which is a TRIR of 3.0.





As part of our commitment to Diversity and Inclusion, we deployed a Diversity and Engagement survey early in the year and used the findings to identify opportunities for growth. We were pleased to have more than 80% participation in the voluntary survey and were encouraged by the general feedback. We identified areas where action was possible and we took action immediately. Other areas of improvement, like recruiting and hiring practices, are being woven into policy changes and future activities.

Additionally, we continued to develop our leadership team and board. In 2020 Fernando Araujo joined as Chief Operating Officer. Danielle Hunter joined as General Counsel and Corporate Secretary as well. And throughout the organization, we continued to assess positions and retain and recruit diverse, top-grade talent as part of our evolution.

2020 was a challenging year no doubt. However, we are prepared to face this evolving context, and we are committed to and capable of providing affordable energy in an environmentally responsible and safe manner. We believe we can partner with states to help achieve their long-term environmental goals while also meeting the demands for energy today. All of us at bry are focused on creating value for all stakeholders. We are proud of the fact that in 2020 we delivered on our commitments and executed our plan in spite of it all.

A.T. (TREM) SMITH
Board Chair, Chief Executive Officer & President,
Berry Corporation (bry)

"We believe good governance is the foundation of success, which is exemplified by our strong track record of safety and environmental stewardship, our corporate culture, and the 'bry First' principle that seeks a win-win approach for all of our stakeholders, including shareholders, employees, the environment, and the communities where we operate."

A.T. (TREM) SMITH
Board Chair, Chief Executive Officer & President,
Berry Corporation (bry)

2020 ESG REPORT

CORE VALUES

- **Leadership**
- **Entrepreneurship**
- **Accountability**
- **Ownership**
- **Communication**

ESG Oversight

BRY believes that to lead in environmental, social and governance (ESG), ESG must be fully integrated into our overall corporate strategy.

To ensure its holistic implementation, our ESG initiatives are managed within a governance structure that embraces broad engagement and provides a clear line of accountability. The Board of Directors oversees bry's ESG goals as part of its oversight of our corporate strategy and risk management. The Nominating and Governance, Compensation, and Audit Committees assist the Board in discharging its oversight of our programs and practices to address ESG issues and actively monitor our performance and risks. In 2020, we formalized the internal, cross-functional ESG Steering Committee responsible for developing and implementing the ESG strategy, setting goals and priorities, assessing risks and opportunities, and deploying thoughtful, systematic programs and practices that drive performance. A working sub-group proactively and strategically identifies opportunities to execute.

ESG Reporting and Stakeholder Engagement

We launched our ESG reporting program in 2020 to collect ESG data and publicly disclose our progress. To help inform our ESG strategic priorities, and what we report, we engage with our key stakeholders.

Environmental Responsibility

We are committed to operating in a manner that maintains, protects, and preserves our natural resources and that promotes a safe and healthy workplace. We aim for 100% compliance with all legal requirements related to operations, including air, water, and greenhouse gas emissions standards.

MEASURING OUR ENVIRONMENTAL PERFORMANCE

In 2020, we voluntarily hired an outside firm to calculate and assess our Greenhouse Gas (GHG) emissions, water use and recycling, and solid waste generation and recycling, using our 2019 activities to establish a baseline. The results identified improvement opportunities and revealed where more data is necessary to identify existing impacts and opportunities for improvement. We will be setting targets for GHG reduction, increasing our beneficial use of produced water, and reducing our solid waste footprint, and look forward to communicating progress to our stakeholders over time.

OUR WORK NOW: PROTECTING OUR AIR, WATER AND LAND

Even prior to our commitment to comprehensive measurement and reduction in emissions, bry was taking action. We reduce GHG emissions from our operations by using cogeneration power plants that reuse heat to produce both steam and electricity together. This results in both cost efficiencies and reductions in GHG emissions. Our cogeneration activity produces enough electricity to power approximately 100,000 homes annually, and we report our GHG emissions to both the California Air Resources Board (CARB) under California's Global Warming Solutions Act, and the U.S. Environmental Protection Agency under the Clean Air Act.

Emissions Management

We have robust internal processes to ensure compliance with the federal Clean Air Act and the California Clean Air Act, as well as federal and state laws designed to reduce GHG emissions. We regularly coordinate with the California Environmental Protection Agency and California Air Resources Board (CARB) staff, as well as local air districts on projects and issues outside the scope of day-to-day compliance. For example, we partnered with CARB on a methane mitigation project where CARB conducted surveys of oil field operations in fall 2020. BRY identified oil infrastructure to be surveyed, inspected methane plumes that were identified during the surveys, mitigated the identified plumes, and reported findings back to CARB. BRY was first to engage with CARB, had only a few leaks identified by CARB during the 6 week flyover program, and was first among participants from multiple industries to resolve identified emission sources.

We also have supervisory control and data acquisition (SCADA) systems that can be used to help monitor flow levels and help ensure that fluids and gases remain in the pipelines and tanks in which they belong.

Water Consumption and Management Practices

We produce the vast majority of the water we use in 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 and water flooding and well drilling, completion, and stimulation. We efficiently use water supplied from various local and regional sources, particularly for power plants and to support operations like steam injection in certain fields.

We are an original member and board member of the Eastside Water Management Area (EWMA) in Kern County, CA, which aims to manage groundwater in a way that is sustainable and provides for agricultural, industrial and other beneficial uses in compliance with California's Sustainable Groundwater Management Act (SGMA). Through EWMA, we coordinate with a variety of stakeholders on groundwater management issues.

Waste and Waste Disposal Management Practices

We are enhancing internal reporting functions to better account for solid waste generation and management. Initial surveys of our baseline of solid waste generation and management practices are a component of our 2019 survey. Improved internal reporting processes implemented in late 2019 will help identify opportunities to reduce solid waste and guide future reduction, reuse, or recycling practices.

Idle Well Management

For each new well we drill, we account for future costs of abandonment and decommissioning of both the well and associated facilities. These costs, or Asset Retirement Obligations (ARO), are publicly disclosed in financial statements filed with the Securities and Exchange Commission (SEC). To meet California's additional idle well management regulations, bry maintains plans for the management of all idle wells. The State has also passed several important new statutes in recent years aimed at ensuring that oil and gas producers manage their idle well inventories by either returning wells to service or plugging those wells that have become idle. The new statutes include:

- **2019 new idle well regulations:** Require a comprehensive well testing regime to prevent leaks, a compliance schedule for testing or plugging and abandoning idle wells, the collection of data necessary to prioritize testing and sealing idle wells, a long-term idle well management plan, an engineering analysis for wells idled 15 years or longer, and requirements for active observation wells.
- **AB 2729:** Increased idle well fees, discouraging operators to keep large numbers of idle wells and requiring operators to plug between 4-6% of their idle wells annually.
- **AB 1057:** Allows the State Oil and Gas Supervisor to require any operator in the state to post an additional security bond or alternative compliance mechanism up to $30 million to cover future estimated costs of well abandonment.
- **SB 551:** Requires operators to give the California Geologic Energy Management Division (CalGEM) an estimation of their future plugging and abandonment obligations as well as their plan to meet those obligations.

BRY spent $17 million and decommissioned 194 wells in 2020. This amount is more than the regulatory requirement, in part to accommodate operational needs but largely because bry recognizes that there are multiple economic, policy, and public health and safety reasons to reduce the number of wells that simply will not return to service. In some instances, bry was abandoning wells earlier than required.

Biodiversity Policies

Protecting and preventing harm to wildlife is a shared responsibility. BRY's operations in some areas must coexist with threatened and endangered species. BRY adopted policies to protect against harm to threatened, endangered, or otherwise protected species or their habitats specifically, and to wildlife generally. Those policies include:

- regular, site-specific trainings for employees on identifying plant and animal species that may be present on our leases,
- training on conducting operations so as to avoid creating nuisances for wildlife, and on operating machinery to avoid harm to wildlife,
- training and operational standards for minimization of spills and the importance of immediate clean up when spills occur, and,
- covering of tanks and moving equipment to protect wildlife near those facilities.

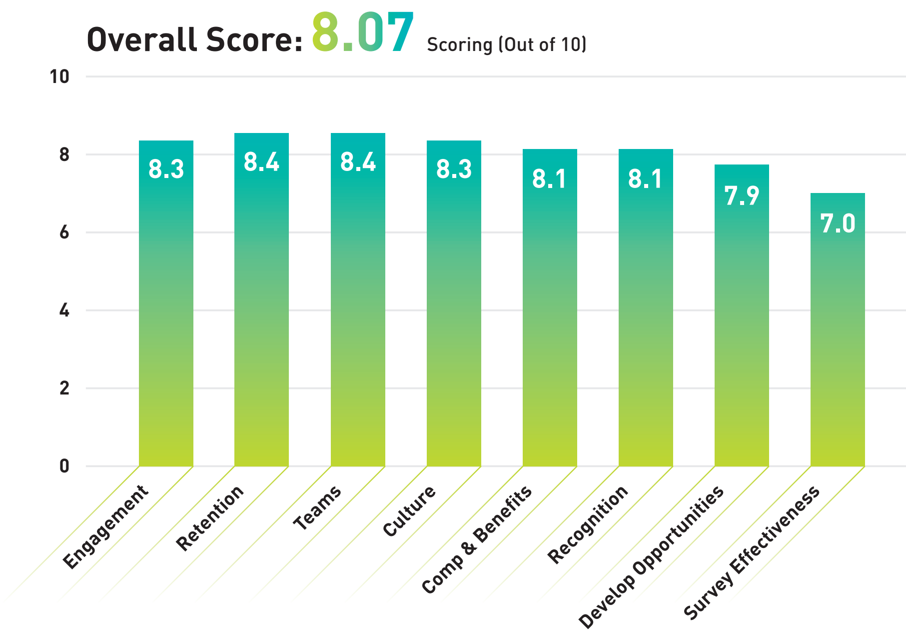
BRY staff also work regularly with the U.S. Fish and Wildlife Service (USFWS), the California Department of Fish and Wildlife (CDFW), the Bureau of Land Management (BLM), and other agencies concerned with the protection of habitats and wildlife as we strive to comply fully with federal and state laws and regulations designed to protect wildlife including the Endangered Species Act, the Migratory Bird Treaty Act, the California Endangered Species Act, and others.

Social Responsibility

Our people and the communities where we operate are our strongest differentiator and asset. Selecting, developing and fostering the best talent, and providing an inclusive culture are critical to our success.

EMPLOYEE ENGAGEMENT

We use a variety of channels to facilitate open, direct and honest communication: periodic town hall meetings, performance conversations and reviews, and our annual employee engagement survey. Our Engagement Survey (6/5/19 - 7/5/19) had a 78.2% participation rate and an **83% overall favorability rating**. Additionally, the voluntary turnover in 2019 and 2020 were 7.9% and 8.2%, respectively.



We attract and retain highly talented and experienced women to our workforce. Currently our senior management team is 33% women and our total workforce is approximately 20% women. We aim to increase these percentages in the coming years.

OUR COMMITMENT TO DIVERSITY AND INCLUSION

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 by:

- Recognizing the rich dimensions of diversity contained within each individual;
- Valuing individuals and groups free from prejudice, discrimination and bias; and
- Practicing equity and respect to build alliances across differences.

This means ensuring an inclusive environment for everyone, regardless of race, color, ethnicity, religion, sex (including pregnancy), sexual orientation, gender identity and/or expression, national origin or citizenship, age, disability (physical or mental), parental status, marital status, political affiliation, veteran status, socioeconomic status or background, neuro(a)typicality, or physical appearance. This applies to our employee recruitment and selection process, operation of our business, and our partnerships. We adhere to equal employment opportunity policies and practices, prohibit discrimination and harassment of any type, and aim to only do business or partner with organizations that share our commitment to diversity and inclusivity and do not involve or engage in exclusionary membership practices.

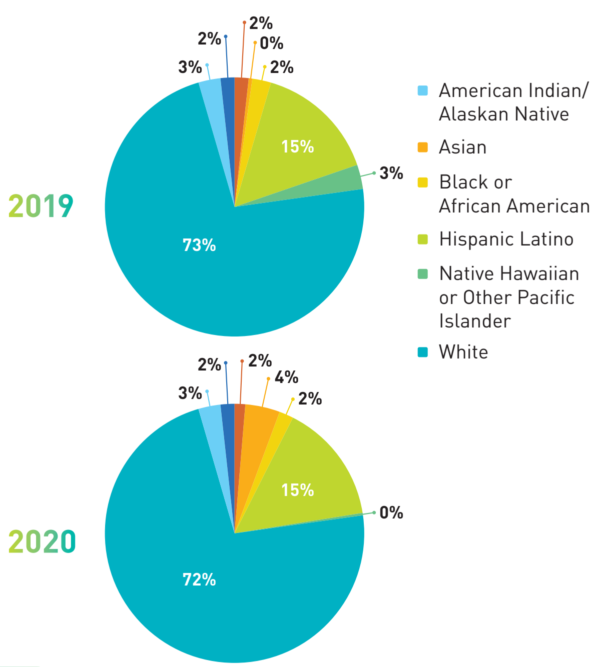
2020 D&I COMMITMENTS

In response to events in 2020 that prompted a national discourse around equality in our society, our Executive Team released a series of communications to all bry employees expressing support for those fighting for a more equitable and just society, reaffirming bry's commitment to diversity, equity and inclusion, and emphasizing unequivocally that there is absolutely no room in our company for hate, intolerance, discrimination, prejudice, or harassment of any kind, whether obvious or covert, conscious or unconscious. Simultaneously, we announced new, company-wide initiatives, which included enhanced inclusion and diversity training, an employee survey on the bry work environment, and a full review of our workplace policies and practices. The survey served as an opportunity to hear from our employees, understand their experiences and needs, and ensure that we foster a safe, supportive, and equitable work environment. In response to the survey results, we announced the following actions:

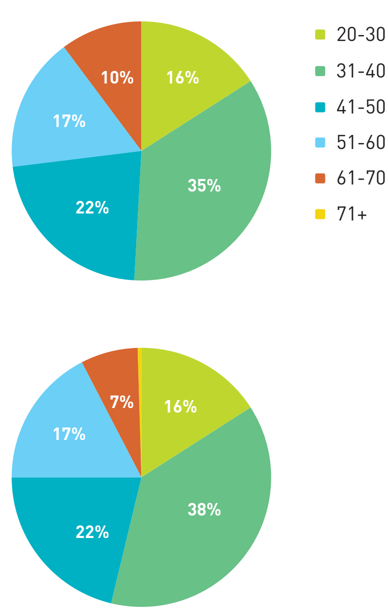
- Enhancing the HR team with an Organizational Behavior and Development Manager
- Communicating definitions of diversity and inclusion in visible places throughout the workplace
- Providing diversity and inclusion training for all employees
- Sourcing external diversity and inclusion training for managers
- Offering more transparency in recruiting efforts
- Committing to a community outreach day focused on fostering diversity and cultural awareness
- Giving financial support to organizations focused on justice and equality. A full list of organizations bry supports is available online.
- Continuing to listen and seek feedback and input

2019 / 2020 ORGANIZATION WIDE DIVERSITY STATS

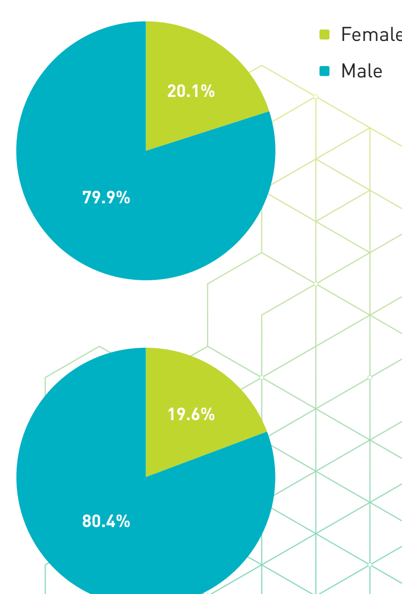
Race



Age



Gender



INVESTING IN OUR TALENT

We reward our talented employees for their hard work, qualities, experience and passion. The Compensation Committee has oversight responsibilities for bry's human capital management policies, processes and practices related to workforce diversity, wage and opportunity, equality, and inclusion. This includes reviewing employment policies, processes, and practices related to employee recruitment, retention and development, and succession planning, as well as our compensation and incentive structure that is tied to safety and environmental responsibility performance. The committee looks at these practices with the lens of diversity, fairness and equality, and inclusion. Our comprehensive and competitive benefits support the health and well-being of our employees and their families, while also offering opportunities for professional growth and development. This year, we identified and filled the need for an Organizational Behavior and Development Manager to ensure we are taking care of our people and helping employees maximize their potential.

SUPPORTING OUR WORKFORCE AND OUR COMMUNITIES DURING COVID-19

The health and safety of our employees and their families, our communities, healthcare providers and other frontline workers are our top priorities. It is imperative that our people are safe and healthy, while continuing to supply affordable, reliable, and locally sourced energy to ensure the economic and social well being of our customers.

BRY continuously monitors federal, state and local guidance, as well as that of the Centers for Disease Control and Prevention (CDC), and Company protocols and policies are updated as appropriate. We have adopted the following protocols that align with the recommendations of the CDC and others:

- Established a bry COVID-19 cross-functional response team, which meets each week to review recent developments and guidance, assess the bry team's work-from-home status and effectiveness, and identifies any appropriate response actions.
- Identified and tasked HR as the initial point of contact for all COVID-19 potential exposure and related sick cases. HR reviews each case individually and evaluates potential risks with Health & Safety (H&S). HR and H&S takes immediate action, coordinates with Legal and executes as appropriate, provides necessary guidance, and coordinates and tracks all efforts.
- Offered "Coronavirus 101 – What You Need to Know" training online to ensure our people have the right information to protect against, recognize, and prevent the virus' spread at work.
- Required that essential personnel practice protective and social distancing measures to ensure the ongoing safe operations of our critical infrastructure.
- Implemented a temporary flexible Work From Home protocol to support employees who are caring for their families and to minimize the probability of spreading the COVID-19 virus.

As the COVID-19 pandemic continues, a second health crisis is growing with many Americans struggling with stress, anxiety, depression, and loneliness. BRY made the following resources available to provide extra support for employees' mental health needs:

- 24/7 Telemedicine and Nurse Live
- Resources focused on helping employees and their families stay healthy
- An Employee Assistance Program (EAP) that provides support through confidential counseling sessions, financial and legal counseling, and much more.

INVESTING IN OUR COMMUNITY AND THE FUTURE

BRY is committed to the communities where we operate. We annually participate in educational and recruitment outreach programs such as local university job fairs, career expos, and internship opportunities, and middle and high school info sessions and career days. In 2020, bry donated to a diverse group of more than 40 charitable organizations, contributing more than $150,000. (A full list of organizations bry supports is available online). In addition, we implemented new initiatives in 2020 to strengthen our communities and empower our employees to volunteer and donate, including:

- Updating our Charitable Contribution Policy to allow for employees (1) to submit donation and sponsorship opportunities to the company for consideration, and (2) to apply for donation matching, up to a certain amount, for qualified organizations.
- Establishing a company-sponsored volunteering program that provides employees with PTO benefits to volunteer with organizations and participate in civic activities. Designed to support Diversity & Inclusion in the workplace, this program empowers employees to safely invest their time in accordance with their unique interests, beliefs, and priorities.
- Participating in clothing and food drives for local homeless shelters and food banks.
- Funding organizations and scholarships focused on equity, diversity and inclusion, and criminal justice reform.

OUR COMMITMENT TO OUR INDIGENOUS NEIGHBORS

We recognize and respect the rights, cultures, interests, and aspirations of indigenous peoples affected by our activities in Utah's Uinta Basin. We are committed to pursuing long-term and sustainable relationships with indigenous nations in and around our operations through volunteering, donations, employing tribal members and sourcing from tribal companies to the greatest extent possible.

HUMAN RIGHTS STATEMENT

Our Code of Conduct includes a Human Rights Statement that says, "The Company conducts its business in a manner that respects the human rights and dignity of all, and complies with all applicable laws and supports principles that promote and protect human rights, including those in accordance with the United Nations Guiding Principles on Business and Human Rights and the United Nations Global Compact, in its relationships with its employees, suppliers and the communities in which it operates. This Company's commitment is also guided by international human rights principles encompassed by the Universal Declaration of Human Rights, including those contained within the International Bill of Rights and the International Labor Organization's 1998 Declaration on Fundamental Principles and Rights Work. The Company forbids the use of child labor, forced labor, (including, without limitation prison labor, bonded labor and indentured labor) or trafficking in persons."

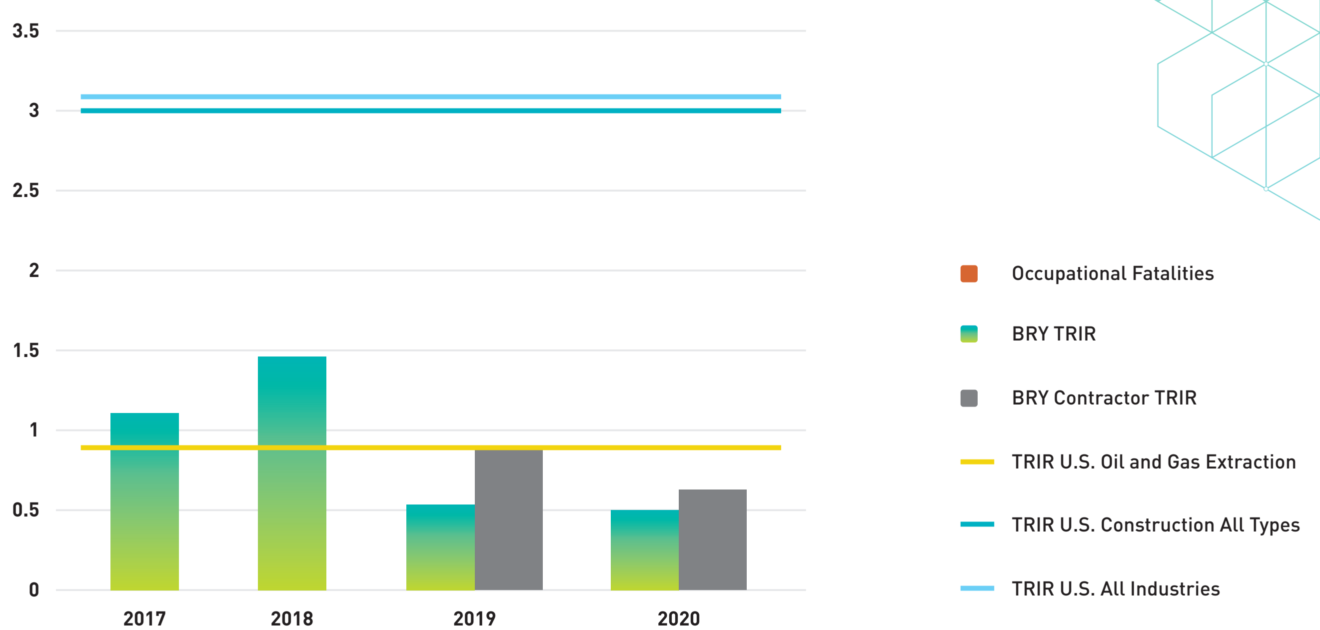
SAFETY FIRST CULTURE

BRY's "safety-first" culture and Environmental, Health & Safety (EH&S) considerations are an integral part of bry's day-to-day operations. We conduct routine and periodic drills, we review contractor training records and health and safety programs before contractors enter our worksites, and we perform periodic compliance audits. BRY maintains EH&S policies and practices, which include:

- Holding our leaders and employees accountable for our EH&S performance;
- Clearly communicating performance requirements and expectations of employees, contractors, and other parties engaged in activities on bry's properties;
- Designing operations to minimize environmental and human health impacts, and providing a workplace free of unmitigated safety hazards;
- Complying with all laws, rules, and regulations governing bry's activities;
- Providing appropriate resources and programs, including professional training;
- Monitoring, evaluating, and periodically reporting EH&S performance to employees; and
- Participating in programs designed to enhance EH&S knowledge, technology, and standards

BRY's annual incident rate, or Total Recordable Incident Rate (TRIR), a measure of the number of recordable occupational injuries or illnesses per 200,000 work hours (i.e., per 100 full-time workers) per year, is six times lower than the rate for all industries. BRY's TRIR over time demonstrates our commitment to worker health and safety. We have had no fatalities among our employees or contractors since we began operating under new management in 2017. Moreover, bry's TRIR has been falling since 2018. In 2020, bry's TRIR was 0.5. The United States oil industry average annual TRIR is 1.0 and for all U.S. construction operations the TRIR is 3.1.

BRY's TRIR Compared to Our Peers



EMERGENCY PREPAREDNESS AND CRISIS RESPONSE

BRY maintains emergency response plans that provide a standard framework for our response to a wide variety of potential crises. We also regularly conduct Incident Command System (ICS) training for our employees and perform drills with our staff and emergency response agencies.

SUPPLIERS AND BUSINESS PARTNERS

Suppliers and contractors play a vital role in our success. Our Supplier Code of Conduct outlines the expectations we have for our suppliers and contractors, which provides the foundation for our procurement policies, guidelines, and practices, as well as our ongoing evaluation of suppliers and contractors.

Governance

We have adopted corporate policies and procedures that promote the effective functioning of our Company to maximize long-term shareholder value, reinforce bry's core values, and ensure that our company is managed with integrity and in the best interest of our shareholders.

BOARD EXCELLENCE

BRY is committed to ensuring its Board follows board excellence best practices such as:

- Size, composition, and structure ensure independent, diverse, and thorough oversight of the Company's material business strategies and risks;
- Annual elections for directors (Board is not classified);
- Majority voting standard for contested elections of directors;
- Require director nominees who receive fewer favorable than unfavorable votes to tender their resignation (Note: This has never happened.);
- Five of seven directors are independent under the NASDAQ standards and SEC regulations (exceeding the NASDAQ requirement for a majority to be independent);
- A Lead Independent Director, with meaningful authority, duties and responsibilities prescribed in the Corporate Governance Guidelines;
- Two women serve on the Board, including the Lead Independent Director, who is also Chair of the Compensation Committee, and the Audit Committee Chair;
- Only independent directors serve on the Audit, Compensation, Nominating and Governance Committees; and
- BRY's independent directors meet regularly in executive sessions.

The full Board has primary responsibility for risk oversight of the Company, with three standing committees dedicated to specific areas of risk: Audit, Compensation, Nominating and Governance. Each member of the Audit and Compensation Committees meet the heightened standards for audit and compensation committee members under the applicable SEC and NASDAQ rules.

Directors are expected to maintain a significant ownership stake in bry to align their interests with shareholders' interests. Based on the Compensation Committee's recommendation, the Board determines the compensation of non-management directors annually. Compensation for independent directors is based on market norms and includes a combination of cash retainers and equity awards. Our executives receive no additional compensation for serving on our Board.

BOARD COMMITTEES

Audit Committee

- Renee Hornbaker (CHAIRPERSON)
- Eugene Voiland
- Anne Mariucci
- Brent Buckley

Compensation Committee

- Anne Mariucci (CHAIRPERSON)
- Brent Buckley
- Donald Paul

Nominating and Corporate Governance Committee

- Donald Paul (CHAIRPERSON)
- Anne Mariucci
- Eugene Voiland

OUR PHILOSOPHY ON BOARD DIVERSITY

The bry Board is committed to a board membership that shares different views and experiences, as well as diversity. Recently the Board added an additional female member who serves as Chair of the Audit Committee.

STOCKHOLDER ENGAGEMENT

We work hard to earn the trust of our stakeholders, and maintaining this trust is essential to bry's future success. As part of our commitment to accountability and communication, we established a dedicated and direct communication channel to the bry leadership team. Shareholders and other interested parties may communicate with our executive team or the Board by emailing our General Counsel, who also serves as Corporate Secretary, at stakeholderengagement@bry.com.

CODE OF CONDUCT

The Code of Conduct and Ethics reflects our commitment to the highest standards of integrity and ethics in all our practices and relationships. We work proactively to ensure employees, directors and business partners understand their obligations to uphold our high ethical, professional and legal standards. Our employees are required to complete an ethics training course when they join the company and annually thereafter. We also require employees to acknowledge and agree to abide by our Code of Business Conduct and Ethics every year. We also have strict and clear policies related to insider trading and conflicts of interest. However, we understand that the Code of Conduct is only a guide. It is the ongoing duty and responsibility of everyone with bry to live by our core values. We expect our people to report violations of company policy, law, or core values and offer confidential reporting channels available at all times. The Audit Committee receives regular reports on complaints reported.

PUBLIC POLICY ADVOCACY AND POLITICAL CONTRIBUTIONS

We have and will continue to proactively engage with the California executive and legislative branches and with regulatory agencies. We build relationships with legislators, regulators and other policymakers by communicating and demonstrating our commitment to state goals and policies in the simultaneous pursuit of our corporate goals. We engage in the legislative and rulemaking processes both directly and indirectly, through trade organizations. We support candidates and political organizations that share and advance our corporate interests. We do all of this ethically and in compliance with all federal, state and local laws, something we achieve by adherence to our policy on political engagement.

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, 2020

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 $266.2 million.

Shares of common stock outstanding as of January 31, 2021: 79,932,806

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held May 19, 2021) will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2020 and is incorporated by reference in Part III to the extent described herein.

Table of Contents

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

Part I

Items 1 and 2. Business and Properties

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

Our Company

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

In the aggregate, our assets are characterized by high oil content, with 100% oil content for our California assets. The overwhelming majority of our productive assets are located in the oil-rich reservoirs in the San Joaquin basin of California, which has more than 150 years of production history and substantial 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 assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah and in the low geologic risk natural gas resource play in the Piceance basin in Colorado.

In California, we solely focus on conventional, shallow oil reservoirs, the drilling and completion of which are low-cost in contrast to unconventional resource plays. For example, the cost to drill and complete the different types of our wells in California typically averages about $375,000 per well. The vertical wells in our Rockies (Utah and Colorado) operations cost approximately $1.5 million per well. In contrast, wells in typical unconventional resources plays cost $5 million to $10 million to drill and complete.

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 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, out-of-period 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.

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 seek proactive and transparent engagement with the many forces impacting our industry and operations, including the regulatory agencies and other government representatives, in order to realize the full potential of our resources in a manner that complies with existing laws and regulations and supports environmental goals. 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.

The Berry Advantage

Our strategy is focused on creating long-term stockholder value by generating Levered Free Cash Flow to fund our operations, optimizing capital efficiency, and returning capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles. Through the extremely low commodity prices that prevailed through most of 2020, we achieved positive Levered Free Cash Flow by protecting prices with oil hedges, reducing costs across the organization, and cutting initially planned capital expenditures. Looking forward, we currently expect Levered Free Cash Flow to break even at approximately $47 Brent, factoring in current interest, projected production levels that are flat year-over-year and no dividends. In April 2020, our Board of Directors decided to temporarily suspend the quarterly dividend that we had consistently paid since our initial public offering ("IPO") in 2018. We reinstituted payment of a quarterly dividend in the first quarter of 2021, subject declaration by our Board of Directors each quarter.

We believe the following competitive strengths will allow us to successfully execute our business strategy:

- ***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 12% to 14%. The nature of our assets provides us with significant capital flexibility (discussed further below) and an ability to efficiently hedge material quantities of future expected production.

- ***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 expected commodity price cycles, which, if prolonged, would allow us to continue returning 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 22% based on the assumptions used in preparing our SEC reserves report as of December 31, 2020. These margins would be substantially greater based on the current strip prices which are more than 35% higher than the prices used for the 2020 reserve calculation. We currently operate approximately 96% 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 cost environment provide us significant visibility and understanding of our expected cash flows.

- ***Brent-influenced crude oil pricing advantage.*** California oil prices are Brent-influenced as California refiners import more than 70% of the state's demand from OPEC+ countries and other waterborne sources. Our highly oil-weighted in-state production, combined with Brent-influenced California pricing, has resulted, and is expected to continue to result, in stronger operating margins than many of our peers.

- ***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, 2020, we had $273 million of liquidity, consisting of $193 million available under our reserves-based lending facility which we entered into on July 31, 2017 (as amended, the “RBL Facility”) and $80 million of cash on hand. As of December 31, 2020, our Leverage Ratio (as defined in our RBL Facility) was 1.8:1.0. 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 living within Levered Free Cash Flows while growing the value of our production and 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:

- ***Live within Levered Free Cash Flow and maintain balance sheet strength and flexibility through commodity price cycles.*** We intend to continue living within Levered Free Cash Flow, which includes funding our capital program and paying interest and dividends, as may be declared by our Board of Directors. We also intend to maintain low leverage by growing organically with excess Levered Free Cash Flow. Our objective is to achieve and maintain a long-term, through-cycle Leverage Ratio (as defined in our RBL Facility) between 1.0x and 2.0x, or lower.

- ***Grow 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. We have found constructive dialogue with regulatory and legislative representatives can help avert compliance and permitting issues. We believe that running our operations in a manner that protects the safety and health of 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 relationships with the communities in which we operate as well as credibility with the relevant agencies governing our operations. 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 enhanced oil recovery ("EOR") 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 also seek to protect our operating expenses through fixed-price gas purchase agreements and other hedging contracts. We have protected a significant portion of our anticipated crude oil production realizations and gas purchases through 2021. We review our hedging program continuously as market conditions change and we will look to begin hedging anticipated crude oil production and gas purchases for 2022 when we see potential inefficiency in pricing compared to market conditions for that period. We make our hedging decisions using a wide range of market data and analysis.

- ***Return capital to our stockholders.*** Our objective is to maintain a disciplined value creation and returns-focused approach to capital allocation in order to generate excess free cash flow. We have a track record of returning capital to our shareholders, primarily in the form of a quarterly dividend which we began paying with our first quarter as a public company and paid regularly through the first quarter of 2020. In the second quarter of 2020, given the historic low oil price environment and the uncertain impact of COVID-19, our Board of Directors decided to temporarily suspended our quarterly dividend. We reinstituted a quarterly dividend in the first quarter of 2021, subject to future determination by the Company's Board of Directors. The Board declared a regular dividend of $0.04 per share on the Company's outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021. Our stock repurchase program, approved by our Board in December 2018, provides an additional opportunity to return value to our existing shareholders. Through December 31, 2019, we had repurchased approximately 6% of our outstanding shares for approximately $50 million and in February 2020 the Board authorized us to repurchase an additional $50 million of stock. In February 2020, the Board also authorized the opportunistic repurchase of up to $75 million of our 2026 Notes. We did not repurchase any of our common stock or 2026 Notes during 2020. If commodity prices increase for a sustained period of time, in addition to a dividend, we would consider repurchasing common stock or our 2026 Notes, as well as repaying debt obligations. 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."

Our Capital Program

For the years ended December 31, 2020 and 2019 our capital expenditures were approximately $69 million and $209 million, respectively, on an accrual basis excluding capitalized overhead and interest, acquisitions and asset retirement spending. We reduced our 2020 capital program from our initial plan, and compared to 2019, in response to significant oil market volatility caused by the unprecedented dual impact of a severe global oil demand decline from the COVID-19 pandemic coupled with a substantial increase in supply from Saudi Arabia and Russia

A substantial majority of our 2020 capital was spent in California whose production increased slightly more than 1% year-over-year. Our California assets produce 100% oil and represent the substantial majority of our value. In 2020, our production in Utah and Colorado decreased 13% year-over-year, as very little capital was deployed to those areas.

Our currently anticipated 2021 capital expenditure budget is approximately $120 to $130 million, which we expect will result in flat year-over-year production and a higher exit rate for 2021 than the beginning of the year. We currently anticipate oil production will be approximately 89% of total production volume in 2021, compared to 88% in 2020 and 87% in 2019. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2021 capital development programs with cash flow from operations and current cash on hand, which was generated during 2020 and anticipated for use to supplement our 2021 capital program.

The table below sets forth the current expected allocation of our 2021 capital expenditure budget by area, with a comparison to the allocation of our 2020 capital expenditures.

	2021 Budget	2020 Actual
	(in millions)	
California	$ 114-120	$ 66
Utah	1-2	1
Colorado	1-2	—
Corporate	4-6	2
Total[(1)]	$ 120-130	$ 69

(1) In 2020 we excluded approximately $6 million of capitalized overhead. The 2021 budgeted amounts include capitalized overhead.

Exclusive of the capital expenditures noted above, for the full year 2020, we spent approximately $18 million on plugging and abandonment activities, exceeding our annual obligation requirements under the California Idle Well Management Program, and in 2021 we expect to spend approximately $19 million to $23 million for such activities.

We currently expect to employ up to three drilling rigs in California during 2021. Additionally, we currently expect to drill approximately 170 to 200 development wells and 10 to 15 delineation wells during 2021, all of which are anticipated to be in California for oil production. The execution of these plans requires regulatory permits and approvals, and changes in laws and regulations, including those relating to the permit review and approval process, could impact our ability to successfully execute our plans.

The amount and timing of capital expenditures are within our control and subject to our management's discretion, and due to the speed with which we are able to drill and complete our wells in California, capital may be adjusted quickly during the year depending on numerous factors, including commodity prices, storage constraints, supply/demand considerations and attractive rates of return. We believe it is important to retain the flexibility to defer planned capital expenditures and may do so based on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the receipt and timing of required regulatory permits and approvals, the availability of necessary equipment, infrastructure and capital, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners, as well as general market conditions. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations. Please see "Regulation of Health, Safety and Environmental Matters" for additional discussion of the laws and regulations impacting our business. For additional information about the potential risks related to our capital program, see "Item 1A. Risk Factors" and for a more detailed discussion of capital expenditures, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Program".

Our Areas of Operation

Our predominant operating area is in California, and we also have operations in Utah and Colorado, which we refer to collectively as our Rockies 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. 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.

We currently hold approximately 15,000 net acres in the San Joaquin basin in Kern County and Ventura basin in Los Angeles County, of which 91% is held by production and fee interest. Approximately 15% 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 99% average working interest in our California assets, and our producing areas include:

- West California operations: (i) our North Midway-Sunset sandstone properties, where we use cyclic and continuous steam injection to develop these known reservoirs; (ii) our North Midway-Sunset thermal diatomite properties, where we utilize innovative EOR techniques to unlock significant value and maximize recoveries; (iii) our South Midway-Sunset, properties, which are long-life, low-decline, strong-margin thermal oil properties with additional development opportunities; (iv) 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.

- East California operations: (i) our Poso Creek property, which is an active mature shallow, heavy oil asset that we continue to develop across the property and (ii) our Placerita Field property in the Ventura basin in Los Angeles County, which is a mature shallow, heavy oil asset with additional recompletion opportunities.

Our California proved reserves represented approximately 91% of our total proved reserves at December 31, 2020. California accounted for 22.9 MBoe/d, or 80%, of our average daily production for the year ended December 31, 2020.

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 five natural gas-fired cogeneration plants that produce electricity and steam. These plants supply approximately 23% of our steam needs and approximately 62% of our field electricity needs 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 three of our cogeneration facilities under power purchase agreement ("PPA") contracts with California utility companies. We also own 74 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 86% of our California oil production is sold through pipeline connections.

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.

Rockies

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 8,000 feet. We have high operational control of our existing acreage, which provides significant upside for additional vertical and or horizontal development and recompletions. We currently hold approximately 93,000 net acres in the Uinta basin, of which 82% is held by production. Approximately 31% of our Utah acreage is on Federal lands administered by the BLM, of which 60% is held by production.

Our Uinta basin proved reserves represented approximately 8% of our total proved reserves at December 31, 2020 and accounted for 4.3 MBoe/d or 15% of our average daily production for the year ended December 31, 2020.

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 15,621 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 101 MBbl/d in 2019. Approximately 84% of Utah's oil production in 2019 came from the Uinta basin in Duchesne and Uintah counties.

Piceance Basin, Colorado

The Piceance basin in northwestern Colorado is a prolific low geologic risk natural gas play with trillions of cubic feet of natural gas in place where we produce from a conventional, tight sandstone reservoir. Our primary operating areas in the Piceance basin are Garden Gulch and North Parachute in northwestern Colorado where we target the Williams Fork formation of the Mesaverde Group and produce at depths ranging from 7,500 feet to 12,500 feet. We have utilized a proven slick water completion method that has resulted in lower costs and increased recoveries. In addition, we have infrastructure and available takeaway capacity in place to support additional development along with existing gas transportation contracts. We currently hold approximately 7,000 net acres in the Piceance basin, of which 100% is held by production and none of which are leased from the BLM.

Our Piceance basin proved reserves represented approximately 1% of our total proved reserves at December 31, 2020 and accounted for 1.3 MBoe/d, or 5%, of our average daily production for the year ended December 31, 2020.

Natural gas generated from coals and carbonaceous shales in the Upper Cretaceous Mesaverde Group migrated into low permeability Mesaverde Group fluvial sandstones resulting in a basin-centered gas accumulation, or what the U.S. Geological Survey terms a "continuous petroleum accumulation." Operators recognized for years that the

Mesaverde Group, and the Williams Fork formation in particular, contained significant quantities of gas over a large area, but the low permeability of the reservoir sandstones made it difficult to complete economic wells. Improvements in hydraulic stimulation design and completion fluids in the 1990s and 2000s, coupled with an increase in commodity prices, led to the economic development of the gas resources in the Piceance basin.

Our Assets and Production Information

For the year ended December 31, 2020, we had average production of approximately 28.5 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, 2020 was 22.9 MBoe/d, of which 100% was oil.

The table below summarizes our average net daily production for the years ended December 31, 2020 and 2019:

	Average Net Daily Production(1) for the Year Ended December 31,			
	2020		2019	
	(MBoe/d)	Oil (%)	(MBoe/d)	Oil (%)
California	22.9	100 %	22.6	100 %
Utah	4.3	50 %	5.0	54 %
Colorado	1.3	2 %	1.4	2 %
Total	28.5	88 %	29.0	87 %

(1) Production represents volumes sold during the period.

Production Data

The following table sets forth information regarding production for the years ended December 31, 2020 and 2019.

	Year Ended December 31,	
	2020	2019
Average daily production(1):		
Oil (MBbl/d)	25.0	25.3
Natural gas (MMcf/d)	18.5	20.0
NGLs (MBbl/d)	0.4	0.4
Total (MBOE/d)(2)	28.5	29.0

(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, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per Mcf, respectively.

Our Development Inventory

We have an extensive inventory of low-geologic risk, high-return development opportunities. As of December 31, 2020, we identified 10,373 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 96% of our producing wells. In addition, a substantial majority of our acreage is currently held by production and fee interest, including 91% of our acreage in California. As of December 31, 2020, the combined net acreage covered by leases expiring in the next three years represented approximately 12% of our total net acreage, of which 11% 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, 2020:

	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	20,136	15,367	91 %	2,739	99 %	94 %	10,373	10,337
Utah	122,251	92,552	82 %	974	72 %	62 %	—	—
Colorado	9,259	6,780	100 %	170	95 %	79 %	—	—
Total	151,646	114,699	84 %	3,883	95 %	89 %	10,373	10,337

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

(2) Of which approximately 15% are BLM acres in California and 31% are BLM acres in Utah.

(3) Includes 510 steamflood and waterflood injection wells in California.

(4) Excludes 90 wells in the Piceance basin each with a 5% working interest.

(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, 2020.

(7) Our total identified drilling locations include approximately 808 gross (805 net) locations associated with PUDs as of December 31, 2020, including 105 gross (105 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, 2020, we had estimated total proved reserves of 95 MMBoe compared to 138 MMBoe as of December 31, 2019. Approximately 91% of the decrease was caused by lower prices used to calculate our proved reserves. Oil prices decreased by 34% and gas prices decreased by 23%, which drove the 26% reduction in our proved reserves, before the effect of current year production. Additionally, the significant drop in 2020 commodity prices resulted in a significant decline in our capital program, limiting opportunities to prove-up additional reserves. Based on current Brent strip pricing the Company expects a material improvement in 2021 proved reserves.

The majority of our reserves are composed of crude oil in shallow, long-lived reservoirs. As of December 31, 2020, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately \$516 million and \$520 million, respectively. 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, 2020, approximately 91% of our proved reserves and approximately 97% of the PV-10 value of our proved reserves are derived from our assets in California. We also have proved reserves in the Uinta basin in Utah, a mature, light-oil-prone play with significant undeveloped resources, as well as in the Piceance basin in Colorado, a prolific natural gas play with low geologic risk.

The tables below summarize our estimated proved reserves and related PV-10 by category as of December 31, 2020:

	Proved Reserves as of December 31, 2020[1]							
	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)[2]	% of Proved	% Proved Developed	Capex[3] ($MM)	PV-10[4] ($MM)
PDP	45	26	1	50	53 %	89 %	24	350
PDNP	6	—	—	6	6 %	11 %	13	61
PUD	39	—	—	39	41 %	— %	430	109
Berry total proved reserves	90	26	1	95	100 %	100 %	467	520
California total proved reserves	87	—	—	87			466	504

(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 $41.77 per Bbl Brent for oil and natural gas liquids ("NGLs") and $2.03 per MMBtu Henry Hub for natural gas at December 31, 2020. The volume-weighted average prices over the lives of the properties were estimated at $39.97 per Bbl of oil and condensate, $9.40 per Bbl of NGLs and $2.19 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 and Production Information—PV-10".

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(3) Represents undiscounted future capital expenditures estimated as of December 31, 2020.

(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 and Production Information—PV-10". PV-10 does not give effect to derivatives transactions.

The following table summarizes our estimated proved reserves and related PV-10 by area as of December 31, 2020. The reserve estimates presented in the table below are based on reports prepared by DeGolyer and MacNaughton. The reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting. Reserves are stated net of applicable royalties.

	Proved Reserves as of December 31, 2020[1]			
	California (San Joaquin and Ventura basins)	**Utah (Uinta basin)**	**Colorado (Piceance basin)**	**Total**
Proved developed reserves:				
Oil (MMBbl)	48	3	—	51
Natural Gas (Bcf)	—	22	4	26
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)[(2)(3)]	48	7	1	56
Proved undeveloped reserves:				
Oil (MMBbl)	39	—	—	39
Natural Gas (Bcf)	—	—	—	—
NGLs (MMBbl)	—	—	—	—
Total (MMBoe)[(3)]	39	—	—	39
Total proved reserves:				
Oil (MMBbl)	87	3	—	90
Natural Gas (Bcf)	—	22	4	26
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)[(3)]	87	7	1	95
PV-10 ($million)[(4)]	$ 504	$ 16	$ —	$ 520

(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 $41.77 per Bbl Brent for oil and NGLs and $2.03 per MMBtu Henry Hub for natural gas at December 31, 2020. The volume-weighted average prices over the lives of the properties were $39.97 per Bbl of oil and condensate, $9.40 per Bbl of NGLs and $2.19 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 11% of total and 12% of oil are non-producing.

(3) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 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.

PV-10

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 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, 2020:

	At December 31, 2020 (in millions)
California PV-10	$ 504
Utah PV-10	16
Colorado PV-10	—
Total Company PV-10	520
Less: present value of future income taxes discounted at 10%	(4)
Standardized measure of discounted future net cash flows	$ 516

Proved Reserves Additions

Our proved reserves in California decreased 27 MMBoe, or 24% before production, almost all which was due to the decreased oil and gas prices year-over-year. The decrease in the Utah reserves of 6 MMBoe was also a result of the low price environment. Oil prices decreased by 34% and gas prices decreased by 23%, which drove the 26% reduction in our proved reserves, before the effect of current year production. Additionally, the significant drop in 2020 commodity prices resulted in a significant decline in our capital program, limiting opportunities to prove-up additional reserves. The total changes to our proved reserves from December 31, 2019 to December 31, 2020 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, 2019	122	15	1	138
Extensions and discoveries	1	—	—	1
Revisions of previous estimates	(28)	(6)	—	(34)
Purchases of minerals in place[2]	—	—	—	—
Current year production	(8)	(2)	—	(10)
Ending balance as of December 31, 2020	87	7	1	95

(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, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per Mcf, respectively.

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

Extensions and Discoveries. During 2020, we added 1 MMBoe of proved reserves from extensions and discoveries solely in our California properties. Our capital program was limited during 2020 due to the low price environment and was focused on production.

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 2020, our total net negative price revision was 20 MMBoe in California and 10 MMBoe in Utah.

This was primarily the result of lower prices in the current commodity price environment. Oil prices have decreased by 34%, and gas prices have decreased by 23%.

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 2020, we had negative technical revisions of 8 MMBoe in California, which was partially offset by positive technical revisions of 4 MMBoe in the Rockies. A portion of the positive technical revisions were related to efficiencies we realized on lease operating expenses.

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 15 MMBoe in 2020 mainly due to price and technical revisions. The Utah proved undeveloped reserves were fully written down due to the decrease in commodity prices. The total changes to our proved undeveloped reserves from December 31, 2019 to December 31, 2020 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, 2019	55	2	—	57
Extensions and discoveries	1	—	—	1
Revisions of previous estimates	(17)	(2)	—	(19)
Reclassifications to proved developed	—	—	—	—
Ending balance as of December 31, 2020	39	—	—	39

(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, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per Mcf, respectively.

Extensions and Discoveries. During 2020, we added 1 MMBoe of proved undeveloped reserves from extensions and discoveries due to drilling unproven locations in Midway Sunset and Belridge Hill.

Revisions of previous estimates.

Revisions related to price - In 2020, our net negative price revision on proved undeveloped reserves were approximately 11 MMBoe in California and 2 MMBoe in Utah, which was primarily the result of lower prices due to the current commodity price environment.

Revisions related to performance - In 2020, our net negative performance-related revision on proved undeveloped reserves was 6 MMBoe in California which resulted primarily from our thermal Diatomite area.

Reclassifications to proved developed. During 2020, we did not transfer any proved undeveloped reserves to the proved developed category due to the limited drilling program resulting from the volatile and low price environment. As a result of a decrease in the capital budget we pushed back new development projects and focused on redevelopment in 2020. We expect to have sufficient future capital to develop our proved undeveloped reserves at December 31, 2020 within five years. Prices substantially below these 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 did 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 33 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, 2020, we have approximately 808 gross (805 net) drilling locations attributable to our proved undeveloped reserves, compared to 1,289 gross (1,276 net) as of December 31, 2019. The decrease in drilling locations attributable to our proved undeveloped reserves is primarily due to the low price environment. We use production data and experience gained 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 9,565 gross (9,533 net) unproven drilling locations as of December 31, 2020, compared to 9,570 gross (9,538 net) unproven drilling locations as of December 31, 2019. 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) potential IOR and EOR 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 EOR). 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 and greater than ten acres for a primary gas expansion development in our Piceance asset in Colorado.

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, 2020.

	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	703	105	8,094	1,471	8,797	1,576
Utah	—	—	—	—	—	—
Colorado	—	—	—	—	—	—
Total Identified Drilling Locations	703	105	8,094	1,471	8,797	1,576

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,		
	2020	2019	2018
SJV Midway Sunset			
Total production[(1)]**:**			
Oil (MBbls)	5,933	5,543	4,495
Natural gas (Bcf)	—	—	—
NGLs (MBbls)	—	—	—
Total (MBoe)[(2)]	5,933	5,543	4,495

	Year Ended December 31,		
	2020	2019	2018
SJV Belridge Hill			
Total production[(1)]**:**			
Oil (MBbls)	1,280	1,312	1,196
Natural gas (Bcf)	—	—	—
NGLs (MBbls)	—	—	—
Total (MBoe)[(2)]	1,280	1,312	1,196

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

(1) Production represents volumes sold during the period.

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per Mcf, respectively.

Productive Wells

As of December 31, 2020, we had a total of 3,953 gross (3,763 net) productive wells (including 510 gross and net steamflood and waterflood injection wells), approximately 96% of which were oil wells. Our average working interests in our productive wells is approximately 95%. 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.

The following table sets forth our productive oil and natural gas wells (both producing and capable of producing) as of December 31, 2020.

	California (San Joaquin and Ventura basins)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
Oil				
Gross(1)	2,801	982	—	3,783
Net(2)	2,710	931	—	3,641
Gas				
Gross(1)(3)	—	—	170	170
Net(2)(3)	—	—	122	122

(1) The total number of wells in which interests are owned. Includes 510 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, 2020.

	California (San Joaquin and Ventura basins)	Utah and Other (Uinta and Piceance basins)	Total
Developed(1)			
Gross(2)	7,344	48,816	56,160
Net(3)	7,315	42,851	50,166
Undeveloped(4)			
Gross(2)	12,792	82,694	95,486
Net(3)	8,052	56,481	64,533

(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, 2020, we were not participating in any development or exploratory wells. We were participating in 18 steamflood and waterflood pressure maintenance projects - 16 steamflood projects and one waterflood project were located in the San Joaquin basin, and one waterflood project was located in the Uinta basin.

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)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
2020				
Oil[1]	45	—	—	45
Natural Gas	—	—	—	—
Dry	—	—	—	—
2019				
Oil[1][2]	335	3	—	338
Natural Gas	—	—	—	—
Dry	—	—	—	—
2018				
Oil[1]	224	8	—	232
Natural Gas	—	—	—	—
Dry	—	—	—	—

(1) Includes injector wells.

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

Delivery Commitments

We have contractual agreements to provide gas volumes for transportation, processing and sales, some of which specify fixed and determinable quantities and all of which were in Utah. As of December 31, 2020, the volumes contracted to be processed were approximately 7,170 Mcf/d of gas and will decrease to 4,560 Mcf/d in March 2021 and ends February 2023. As of December 31, 2020, our firm pipeline capacity was approximately 35,000 MMBtu/d of gas and decreased to approximately 30,000 MMBtu/d in February 2021 through September 2023. We generally 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 96% 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 and Piceance in Colorado, 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
Colorado	Piceance	Vertical	Proppantless slick water stimulation	Pressure depletion

Thermal 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 and Ventura basins, primarily in Kern County and in fields such as Midway-Sunset, South Belridge, McKittrick, Poso Creek, and Placerita. 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 (300 to 2,500 ft) than our other programs and the wells are relatively inexpensive to drill and complete at approximately $375,000 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 five 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, (ii) another 5MW facility (“21Z Cogen”) located in the McKittrick Field, and (iii) a 42 MW facility (“Cogen 42”) located in the Placerita 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 74 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.

Hydraulic Stimulation

Hydraulic stimulation is an important and common practice that is used to stimulate production of hydrocarbons from tight geologic formations. The process involves the injection of water, sand and trace amounts of chemicals under pressure into formations to enhance the permeability of the surrounding rock and stimulate production. Our California hydraulic stimulation projects use significantly lower fluid and sand volumes than is typical in other areas. For example, we expect to use approximately 150 thousand gallons of water per well for our hydraulic stimulations compared to a median of nearly 15 million gallons for horizontal, unconventional shale wells hydraulically stimulated in the United States. Similarly, we expect to use only about 300 thousand pounds of sand per well compared to a nationwide average of over 15 million pounds of sand per well. We use low-volume hydraulic reservoir stimulation in the San Joaquin basin to stimulate our non-thermal Diatomite reservoir at the Hill property. We have applied this technique for years and plan to continue this stimulation method on our inventory of Hill non-thermal Diatomite development wells.

We use more traditional hydraulic stimulation techniques to complete our wells in the Piceance basin. However, in this area, we use a more advanced technique known as “proppantless stimulation” to stimulate the reservoir with water and no proppant, such as sand.

Marketing Arrangements

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

Crude Oil. Approximately 86% 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 more than 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. As of December 31, 2020, all of our oil production was sold 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. As of December 31, 2020, all of our natural gas and NGL production was sold 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. The relatively small volumes of condensate produced in Colorado are sold under market-based short-term contracts.

Gas Purchasing. We enter into hedges for gas purchases to protect our operating expenses from price fluctuations.

Electricity Generation. Our cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. The total nameplate electrical generation capacity of our five cogeneration facilities, which are centrally located on certain of our oil producing properties, is approximately 108 MW. The steam generated by each facility is capable of being delivered to numerous wells that require steam for our EOR 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, 2020, we sold approximately 1,800 megawatt-hours ("MWhs") per day of cogen power into the grid and consumed approximately 300 MWhs per day of cogen power for lease operations. The five cogeneration facilities produced an average of approximately 37,000 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 three 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 2021 and 2026. We are currently in discussions with the counterparty with regards to the PPA expiring in 2021.

Principal Customers

For the year ended December 31, 2020, sales to Marathon Petroleum, Phillips 66 and Kern Oil & Refining accounted for approximately 44%, 20%, and 12% respectively, of our sales. At December 31, 2020, trade accounts receivable from three customers represented approximately 38%, 15% 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. 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. 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 and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling and completion objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may have been and in the future may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires and rain.

Natural gas prices 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.

Regulation of Health, Safety and Environmental Matters

Like other companies in the oil and gas industry, our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- Establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, and attainment plans to meet those regional standards, which may significantly restrict development, economic activity and transportation in the region;
- require the acquisition of various permits before drilling, workover production, underground fluid injection, enhanced oil recovery methods, or waste disposal commences;
- 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 notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive safety and pollution control equipment—such as leak detection, monitoring and control systems—to prevent or reduce the release or discharge of regulated materials into the air, land, surface water or groundwater;

- restrict the types, quantities and concentration of various regulated materials, including oil, natural gas, produced water or wastes, that can be released into the environment in connection with drilling and production activities, and impose energy efficiency or renewable energy standards on us or users of our products;
- 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; and
- require the purchase of allowances to account for our GHG emissions if we are unable to reduce our emissions below the California statewide maximum limited on covered GHG emissions.

California, where most of our operations and assets are located, is one of the most heavily regulated states in the United States. Before an oil and gas operator can pursue drilling operations in California, they must obtain local government permission to engage in an oil and gas production land use, including constructing production facilities and drilling wells, in addition to certain state permissions and authorizations. Local governments in California must conduct an environmental impact review ("EIR") to review the environmental impact that their decisions regarding land use may cause, including the impact of such decisions on habitat, neighboring communities, air quality, water quality, and other environmental considerations. This fundamental requirement of the California Environmental Quality Act ("CEQA") is mirrored in the National Environmental Protection Act ("NEPA") for approvals of land uses on federal lands.

Under CEQA, if the local government does not conduct the review of their land use decision, then subsequent permitting agencies may be required to instead conduct the environmental review for the project. For instance, if the local government does not conduct the requuired EIR for allowing an oil and gas production land use, then CEQA requires that the agency responsible for issuing the permit to actually drill the wells (which is distinct from allowing use the land for oil and gas operations) conduct the required EIR before issuing the permit to drill. This element of CEQA has and will continue to impact our ability to obtain permits, most significantly until the ongoing litigation challenging the sufficiency of Kern County's EIR for CEQA compliance is resolved, which is further discussed below.

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. Government actions, including the issuance of certain permits or approval of projects, by state, local, or federal agencies that are subject to environmental reviews, required by either CEQA or NEPA, may experience delays, have mitigation measures imposed, or be delayed by litigation. For example, prior to issuing permits necessary for the conduct of certain operations, CalGEM requires an operator to identify the manner in which CEQA has been satisfied. Historically, we could satisfy this requirement by referencing the Kern County EIR (the "Kern County EIR") covering oil and gas operations in Kern County. However, as discussed below, the use of that EIR has been suspended, requiring compliance with CEQA to be otherwise demonstrated. Demonstrating such compliance is time and cost intensive, or requires that the proposed drilling meets one of a few, limited exemptions to CEQA. While "infill drilling" has been considered exempt in the past, CalGEM appears to be limiting the instance where it considers proposed drilling as 'infill" of areas already given over to oilfield uses and impacts.

In April 2019, new idle well regulations went into effect in California, which includes a comprehensive well testing regime to demonstrate the mechanical integrity of idled 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. Operators can avoid paying certain idle well fees and limit testing requirements if they implement an idle well management plan that requires plugging of a certain number of idles wells annually. 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. We have submitted an idle well management plan and are meeting the conditions of that plan to meet our obligations.

Also, in 2019, the Governor of California signed AB 1057, legislation that required state agencies to review emissions from idle and abandoned wells, evaluate plugging and abandonment and restoration costs and associated bonding requirements. This legislation also expanded CalGEM's duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

Effective April 2019, CalGEM also finalized new Underground Injection Control ("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. Our California development and production activities are subject to UIC regulations. With the changes in the UIC regulations and its impact on the permitting process, we experienced delays in obtaining the permits required to continue our planned drilling operations over the latter half of 2019 and into 2020. Our 2020 plans were informed, ultimately, by these permitting issues that we began to observe in late 2019 and early 2020, and then were later modified due to the deterioration of market conditions resulting from the COVID-19 pandemic. Accordingly, our 2020 results were not significantly affected because we were able to obtain the permits necessary to support our planned activities.

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) review and updating of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the Legislature in 2019; and (3) a performance audit of CalGEM's processes for issuing well stimulation treatment ("WST"), also known as hydraulic fracturing or "fracking", permits and PALs for underground injection activities by the State Department of Finance and an independent review and approval 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. Only our undeveloped thermal diatomite assets have been, and continue to be, impacted by the moratorium on approval of new high–pressure cyclic steam wells. Our 2020 results were not significantly impacted by the moratorium because our operating plan did not require new high–pressure cyclic steam injection and the moratorium does not impact existing production or previously approved permits. We also do not expect our 2021 results to be impacted by the moratorium as our current plans for the year do not include new high–pressure cyclic steam wells.

In Kern County, we typically have satisfied CalGEM's request for proof of CEQA compliance by demonstrating the Company's compliance with the local oil and gas ordinance, which was supported by the Kern County EIR, as certified by the Kern County Board of Supervisors in 2015, discussed above. A group of plaintiffs challenged the Kern County EIR and on February 25, 2020, the California Fifth District Court of Appeals issued a ruling that invalidates a portion of the Kern County EIR, effective 30 days after entry of the ruling, until Kern County makes certain revisions to the Kern County EIR and recertifies it ("Kern County Ruling"). 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. To address the Kern County Ruling, Kern County elected to prepare a supplemental EIR. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in the supplemental EIR, though it must be approved by the county Board of Supervisors before becoming effective. It is currently expected to be finalized and approved in the first half of 2021, although the timing of such is uncertain and the approval of such could be significantly delayed; the supplemental EIR and certification may also be subject to litigation. The Kern County Ruling does not invalidate existing permits and so has not materially affected our plans and operations to date. However, we are now experiencing delays in obtaining new permits and approvals to enable our current and future plans, and we cannot predict whether this supplemental EIR will result in the imposition of more onerous permit application requirements or other requirements or restrictionson exploration and production activities. While the near- and longer- term effects of the Kern County Ruling, and Kern County's attempts to resolve the ruling with the supplemental EIR, on oil and gas activities in Kern County are not yet fully known, we are actively monitoring the course of proceeding and evaluating the potential impact to our operations and plans. Our 2021 plans may be impacted by delays in resolving the Kern County Ruling and approval of the supplemental EIR, as well as other existing and pending regulatory changes or government activity impacting the timing of, and conditions imposed on, obtaining required permits and approvals. If we are unable to obtain the required permits and approvals on a timely basis or at all, our financial and operating results could be adversely impacted.

In September 2020, Governor Gavin Newsom of California issued an executive order (the "Order") that seeks to reduce both the supply of and demand for fossil fuels in the state. The Order establishes several goals and directs 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 State Legislature to enact new laws prohibiting hydraulic fracturing in the state by 2024. The Order also directs CalGEM to finish its review of public health and safety concerns from the impacts of oil extraction activities and propose significantly strengthened regulations, which may include setbacks, to address these concerns by December 31, 2020, though this deadline was subsequently extended to Spring 2021. In October 2020, the Governor issued an executive order that establishes a state goal to conserve at least 30% of California's land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity. At this time, we cannot predict how implementation of these two executive orders may impact our operations.

In response to the Order, 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 (fracking), 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. As proposed, SB 467 will also prohibit 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. The ultimate outcome of Senate Bill 467 or any other proposed legislation remains uncertain at this time, as past measures to further impose additional stringent requirements upon oil and gas activities in the California legislature were not successful. For example, in both 2019 and 2020, California considered legislation to impose a statewide setback distance between certain oil and natural gas operations and residences, schools, and healthcare facilities. However, in both cases, the proposal failed to receive the approval of the California State Senate.

Existing and potential future laws, rules and regulations may restrict 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 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, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on operations. For more information related to regulatory risks, see "Item 1A. Risk Factors—**Risks Related to Our Operations and Industry**".

The environmental laws and regulations applicable to us and our operations include, among others, the following U.S. federal laws and regulations:

- Clean Air Act (the "CAA"), which governs air emissions;
- Clean Water Act (the "CWA"), which governs discharges to and excavations within the waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes liability where hazardous substances have been released into the environment (commonly known as "Superfund");
- 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;
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- 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;
- SDWA, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which regulate oil and gas production activities on federal lands and impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. Our planned capital expenditures depend on a variety of factors, including but not limited to the receipt and timing of required regulatory permits and approvals. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and materially affect our business, financial condition and results of operations. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulations, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, natural gas and NGLs that may be produced from our wells and to limit the number of wells or locations we can drill. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

We believe that compliance with currently applicable 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 environmental regulations. Future regulatory issues that could impact us include new rules or legislation, or the reinterpretation of existing rules or legislation, relating to the items discussed below.

Climate Change

The potential threat of climate change due to man-made 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 greenhouse gases ("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 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. Similar regulations applicable to oil and gas facilities have been promulgated in Colorado (see below).

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. 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, 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. The impacts of this executive order, and the terms of any legislation or regulation promulgated to implement the United States' commitment to the Paris Agreement, are unclear at this time.

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 January 27 order also suspends the issuance of new leases for oil and gas development on federal lands to the extent permitted by law; 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. 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. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. 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.

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.

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."***

Hydraulic Stimulation

Hydraulic stimulation is an important and common practice that is used to stimulate production of hydrocarbons from tight geologic formations. The process involves the injection of water, sand and trace amounts of chemicals under pressure into formations to enhance the permeability of the surrounding rock and stimulate production. Recently, as part of their oil and natural gas regulatory programs, state regulators have overseen hydraulic stimulation operations in more detail. However, from time to time, federal agencies have asserted regulatory authority over certain aspects of the process. The EPA has 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. The BLM previously 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 of this litigation could materially impact our operations in the Uinta basin and other areas. 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 result in delays in operations at well sites and also increased costs to make wells productive.

There may be other attempts to further regulate hydraulic stimulation under the SDWA, the Toxic Substances Control Act and/or other executive or regulatory mechanisms. 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 that the federal government merely holds in trust). Approximately 15% and 31% of our net acreage in California and Utah, respectively, is on federal land; none of our net acreage in Colorado is on federal land. 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.

Moreover, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could restrict hydraulic stimulation in certain circumstances or otherwise impose enhanced permitting, fluid disclosure, or well construction requirements on hydraulic stimulation activities. For example, in Colorado, there have been several initiatives underway to limit or ban crude oil and natural gas exploration, development or operations. On November 23, 2020, the Colorado Oil and Gas Conservation Commission ("COGCC") adopted comprehensive rule changes to fulfill the mandate of Senate Bill 19-181; these new rules are effective as of January 15, 2021 and cover a variety of matters related to public health, safety, welfare, wildlife, and environmental resources. Most significantly, these rule changes establish more stringent setbacks (2,000-feet, instead of the prior 500-foot) on new oil and gas development and eliminate routine flaring and venting of natural gas at new and existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring even greater setbacks. Separately, in California, several bills have been introduced but failed to advance in the California Legislature to impose a statewide setback distance between certain oil and natural gas operations and residences, schools and healthcare facilities. However, such legislation may be considered again in future sessions of the California Legislature. For example, Senate Bill 467 ("SB 467") was introduced into the California State Senate in February 2021. SB 467 would prohibit the issuance of permits for hydraulic fracturing, steam flooding, water flooding, and certain other well stimulation practices beginning January 1, 2022 and completely prohibit the performance of any of these well stimulation practices beginning January 1, 2027. The bill would also allow local governments to prohibit such well stimulation practices prior to 2027. Although other bills to limit well stimulation treatments have previously been introduced and failed to pass through the California legislature, we cannot predict the outcome of this most recent legislative effort; however, any restrictions on the use of well stimulation treatments may adversely impact our operations.

As described above, the regulation or prohibition of hydraulic stimulation is the subject of significant political activity in a number of jurisdictions, some of which have resulted in tighter regulation including recognition of local government authority to implement such restrictions. Many of these restrictions are being challenged in court cases. If new laws or regulations that significantly restrict hydraulic stimulation are adopted, such laws could make it more difficult or costly for us to perform work to stimulate production from tight formations or otherwise impact the value of our assets. In addition, any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect our revenues, results of operations and net cash provided by operating activities.

Additionally, hydraulic stimulation operations require large volumes of water. Our inability to locate sufficient amounts of water or dispose of or recycle water used in our drilling and production operations, could adversely impact our operations. Drought conditions, competing water uses, and other physical disruptions to our access to water could adversely affect our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic stimulation or disposal of waste, including but not limited to produced water, drilling fluids and other wastes associated with the development or production of natural gas.

The SDWA and the Underground Injection Control ("UIC") Program

The SDWA and the UIC program promulgated under the SDWA and relevant state laws regulate the drilling and operation of disposal wells that manage produced water (brine wastewater containing salt and other constituents produced by natural gas and oil wells). The EPA directly administers the UIC program in some states, and in others administration is delegated to the state. Permits must be obtained before developing and using deep injection wells for the disposal of produced water, and well casing integrity monitoring must be conducted periodically to ensure the well casing is not leaking produced water to groundwater. Contamination of groundwater by natural gas and oil drilling, production and related operations may result in fines, penalties, remediation costs and natural resource damages, among other sanctions and liabilities under the SDWA and other federal and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for groundwater contamination, alternative water supplies, property impacts and bodily injury.

Solid and Hazardous Waste

Although oil and natural gas wastes generally are exempt from regulation as hazardous wastes under the federal RCRA and some comparable state statutes, it is possible some wastes we generate presently or in the future may be subject to regulation under the RCRA or other similar statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including hazardous wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in December 2016, the EPA and several environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as a hazardous waste under RCRA. In keeping with the consent decree, in April 2019, EPA signed a determination that revision of these regulations was not warranted at this time. However, a loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the costs to manage and dispose of generated wastes.

In addition, the federal CERCLA can impose joint and several liability without regard to fault or legality of conduct on classes of persons who are statutorily responsible for the release of a hazardous substance into the environment. These persons can include the current and former owners or operators of a site where a release occurs, and anyone who disposes or arranges for the disposal of a hazardous substance released at a site. Under CERCLA, such persons may be subject to strict, joint and several liability for the entire cost of cleaning up hazardous substances that have been released into the environment and for other costs, including response costs, alternative water supplies, damage to natural resources and for the costs of certain health studies. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Each state also has environmental cleanup laws analogous to CERCLA. Petroleum hydrocarbons or wastes may have been previously handled, disposed of, or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. These properties and any materials disposed or released on them may subject us to liability under CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, to contribute to remediation costs, or to perform remedial activities to prevent future environmental harm.

Endangered Species Act

The federal Endangered Species Act (the "ESA") restricts activities that may affect endangered and threatened species or their habitats. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues its effort to make listing decisions and critical habitat designations where necessary for over 250 species, as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia. The U.S. Fish and Wildlife Service agreed to complete the review by the end of the agency's 2017 fiscal year. The agency missed the deadline but continues to review species for listing under the ESA. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MTBA"). The federal government in the past has pursued enforcement actions against oil and natural gas companies under the Migratory Bird Treaty Act after dead migratory birds were found near reserve pits associated with drilling activities. Although, in January 2021, the DOI finalized new regulations clarifying that only the intentional taking of protected migratory birds is subject to prosecution under the MTBA, this interpretation had been struck down previously in August 2020, when the United States District Court for the Southern District of New York vacated a DOI memorandum that previously established this interpretation, finding it contrary to law. The ESA and MBTA have not previously had a significant impact on our operations. Nevertheless, the designation of previously unprotected species, such as the Greater Sage Grouse (which has become subject to renewed calls for protection), as being endangered or threatened could cause us to incur additional costs or become subject to operating restrictions in areas where the species are known to exist. If a portion of any area where we operate were to be designated as a critical or suitable habitat, it could adversely impact the value of our assets.

Air Emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources (e.g., compressor stations), through the imposition of air emission standards, construction and operating permitting programs and other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (the "NAAQS") for ozone from 75 to 70 parts per billion and completed attainment/non-attainment designations in 2018. In 2016, EPA published a Federal Implementation Plan ("FIP") to implement minor new source review for oil and gas production and processing on tribal lands. In April 2018, the EPA proposed revisions to reportedly streamline the FIP. Although neither the original FIP nor its revisions originally applied to areas of ozone non-attainment, a May 2019 rule extended the FIP to the Indian country portion of the Uinta Basin Ozone Nonattainment Area.

Implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Over the next several years we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. In addition, the EPA has adopted new rules under the CAA that require the reduction of volatile organic compound and methane emissions from certain stimulated oil and natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Subsequently, the Trump Administration has made several attempts to modify CAA regulations related to methane emissions from oil and gas sources. In September 2020, the EPA finalized amendments to regulations, removing the transmission and storage segment from the oil and natural as source category and rescinding the methane-specific requirements for production and processing facilities. These attempts are subject to ongoing litigation, and President Biden has issued an executive order calling for the issuance of regulations that would suspend, revise, or rescind the September 2020 rule and the introduction of new or more stringent emissions standards for new, modified, and existing oil and gas facilities.

In addition, the regulations impose new requirements for the detection and repair of volatile organic compound leaks at certain well sites and compressor stations. In May 2016, the EPA also finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase the costs of development, which costs could be significant.

NEPA

Oil and natural gas exploration and production activities on federal lands are subject to NEPA. NEPA requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases. In July 2020, the Council on Environmental Quality issued final revisions to NEPA regulations that seek to conform the scope of direct, indirect, and cumulative impact analyses for proposed projects subject to NEPA with existing case law; however, these revisions may be subject to change under a new presidential administration. Therefore, the final form or impact of such revisions is uncertain at this time.

Water Resources

The CWA and analogous state laws restrict 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. Under the CWA, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. Pursuant to these laws and regulations, we may be required to develop and implement spill prevention, control and countermeasure plans, (“SPCC plans”) in connection with on-site storage of significant quantities of oil. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit from the U.S. Army Corps of Engineers. The process for obtaining permits has the potential to delay our operations. SPCC plans and other federal requirements require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. Also, in June 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly owned treatment works.

In August 2015, the EPA and U.S. Army Corps of Engineers issued a rule expanding the scope of the federal jurisdiction over wetlands and other types of waters (the “Clean Water Rule”). However, there have been attempts to modify the Clean Water Rule by the Trump Administration. On January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows the definition of jurisdictional water relative to the Clean Water Rule. However, legal challenges to these rulemakings are ongoing, and we cannot predict the outcome of any of this litigation. Additionally, it is possible that a new presidential administration could propose a broader interpretation of the CWA’s jurisdiction. To the extent any final 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.

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. 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, steamflooding 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.

Natural Gas Sales and Transportation Regulations

Section 1(b) of the Natural Gas Act (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC") as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers which engage in a minimum level of natural gas sales or purchases, to submit annual reports regarding those transactions to FERC. Should we fail to comply with this requirement or any other applicable FERC-administered statute, rule, regulation or order, it could be subject to substantial penalties and fines.

Federal Energy Regulations

The enactment of the Public Utility Regulatory Policies Act ("PURPA") and the adoption of regulations thereunder by the FERC provided incentives for the development of cogeneration facilities such as those we own. A domestic electricity generating project must be a Qualifying Facility ("QF") under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs and entities that own QFs generally are relieved of compliance with certain federal regulations pursuant to the Public Utility Holding Company Act of 2005. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a nondiscriminatory basis. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. Effective November 23, 2011, the California utility companies have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. While the California utility companies are still required to enter into new contracts with smaller facilities, such as our Cogen 18 facility, there is no assurance that we will be able to secure new contracts upon the expiration of the existing contracts for our larger facilities. Even if new contracts are available for our larger facilities, there is no assurance that the prices and terms of such contracts will not adversely affect our financial condition, results of operations and net cash provided by operating activities.

State Energy Regulation

The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements between electric utilities and independent electricity producers, such as us, are under the regulatory purview of the CPUC. While we are not subject to direct regulation by the CPUC, the CPUC's implementation of PURPA and its authority granted to the investor-owned utilities to enter into other PPAs are important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California. The CPUC's implementation of PURPA may be subject to change based on past and future determinations by the courts, or policy determinations made by the CPUC.

Operations on Indian Lands

A portion of our leases and drill-to-earn arrangements in the Uinta basin operating area of Utah and some of our future leases in this and other operating areas may be subject to laws promulgated by an Indian tribe with jurisdiction over such lands. In addition to potential regulation by federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations may apply to lessees, operators and other parties on Indian 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 Indian 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 Indian lands.

Pipeline Safety Regulations

The 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. From time to time, PHMSA, the courts or Congress may make determinations that affect PHMSA's regulations or their applicability to our pipelines. These determinations may affect the costs we incur in complying with applicable safety regulations.

Worker Safety

The Occupational Safety and Health Act of 1970 ("OSHA") and analogous state laws regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

Future Impacts and Current Expenditures

We cannot predict how future environmental laws and regulations may impact our properties or operations. For the year ended December 31, 2020, 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 2021 or that will otherwise have a material impact on our financial position, results of operations or cash flows.

Human Capital Resources

As of December 31, 2020, we had 347 employees. Currently, none of our employees are covered under collective bargaining/union agreements.

We consider employee relations to be good. We strive to create a corporate culture that is reflective of our core values, including accountability, ownership, communication, leadership and entrepreneurship. We are committed to the development of our employees and provide learning and engagement opportunities.

Corporate Information

On May 11, 2016, our predecessor, Berry LLC, filed petitions for reorganization in the U.S. Bankruptcy Court (the "Bankruptcy Court") for the Southern District of Texas (collectively, the "Chapter 11 Proceedings"). On February 28, 2017, Berry LLC emerged from bankruptcy as a stand-alone company and wholly-owned subsidiary of Berry Corp. with new management, a new board of directors and new ownership. Berry Corp. was incorporated in Delaware in February 2017 in connection with the Chapter 11 Proceedings. A final decree closing the Chapter 11 Proceedings was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party-in-interest to reopen the case including with respect to certain, immaterial remaining matters. Berry Corp. completed its IPO and its common stock has been trading on the Nasdaq Global Select Market ("NASDAQ") under the ticker symbol "BRY" since July 26, 2018.

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

- Our ability to operate profitably and maintain our business and financial condition are highly dependent on commodity prices, which are driven by numerous factors beyond our control. The COVID-19 pandemic, coupled with actions taken by OPEC+, caused oil prices to decline significantly in the first quarter of 2020 and prices remained below pre-pandemic levels for a prolonged period. If oil prices further decline, 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. For example, these capabilities were severely limited by the oversupply of oil and natural gas resulting from the COVID-19 pandemic, coupled with actions taken by OPEC+. 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.
- 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.
- Our capital program is susceptible to risks, including regulatory and permitting risks, that could materially affect its implementation. For example, we may not drill our identified sites at the scheduled times or at all.
- Competition in the oil and natural gas industry may make it difficult for us to acquire properties, market oil or natural gas, and secure trained personnel.

- We may be unable to make 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 electricity sales, economic market prices and regulatory conditions affect the value of these facilities.
- Our producing properties are located primarily in California, making us vulnerable to risks associated with having operations concentrated in this geographic area. For example, California is prone to fires, mudslides, earthquakes and other natural disasters, any of which could adversely affect our operations.
- 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.
- Information technology failures and cyberattacks could affect us significantly.
- Increasing attention to environmental, social and governance (ESG) matters, and environmental related mandates by the federal or states governments, may adversely impact our operations and our business.

Risks Related to Our Financial Condition

- 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.
- 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. Additionally, we may be unable to obtain sufficient quantities of natural gas to conduct our steam operations economically or at desired levels. Further, 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.
- We may not be able to use a portion of our net operating loss carryforwards and tax attributes to reduce our future U.S. federal and state income tax obligations, which could adversely affect our cash flows.

Risks Related to Regulatory Matters

- Our business is highly regulated and governmental authorities can delay or deny the approvals and permits required to conduct, or change the requirements governing, our operations. Attempts by states to restrict the development and production of oil and gas, including through restrictions on the ability to obtain the approvals and permits necessary for oil and gas exploration, extraction, development and production activities, well stimulation, enhanced production techniques and fluid injection or disposal, could negatively impact our business, financial condition, cash flows, and operating and financial results, and cause us to change or delay the implementation of 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

- 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.
- The payment of any dividends will be at the discretion of our Board of Directors.
- We may issue preferred stock that adversely affects the voting power or value of our common stock.
- We are an "emerging growth company," ("EGC") and are able to take advantage of reduced disclosure requirements applicable to EGCs, 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 such 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.

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.

Attempts by several states 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.

Recently, the state governments of both California and Colorado have taken several actions that could adversely impact oil and gas production in those states. On September 23, 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. That executive order establishes several goals and directs 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 state Legislature to enact new laws prohibiting hydraulic fracturing in the state by 2024. The executive order also directs CalGEM to finish its review of public health and safety concerns from the impacts of oil extraction activities and propose significantly strengthened regulations, which may include setbacks, to address these concerns. Any of these developments may adversely impact both demand for our products or production from our properties.

While the September 23, 2020 executive order does not impose a ban on the issuance of hydraulic fracturing permits, Governor Newsom announced plans to ask the legislature to pass legislation to this effect. 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 (fracking), 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. As proposed, SB 467 will also prohibit 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. Although other bills to limit well stimulation treatments have previously been introduced and failed to pass through the California legislature, we cannot predict the outcome of this most recent legislative effort; however, any restrictions on the use of well stimulation treatments may adversely impact our operations. In both 2019 and 2020, California considered legislation to impose a statewide setback distance between certain oil and natural gas operations and residences, schools, and healthcare facilities. However, in both cases, the proposal failed to receive the approval of the California State Senate.

Separately in Colorado, on November 23, 2020, COGCC adopted comprehensive rule changes, effective as of January 15, 2021, covering a variety of matters related to public health, safety, welfare, wildlife, and environmental resources. Most significantly, these rule changes establish more stringent setbacks (2,000-feet, instead of the prior 500-foot) on new oil and gas development and eliminate routine flaring and venting of natural gas at new and existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring even greater setbacks.

The COVID-19 global pandemic has adversely affected our business, and the ultimate effect on our operations and financial condition will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 global pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. This resulted in a significant reduction in demand for and prices of crude oil, natural gas and NGL, which was compounded by certain actions taken by members of OPEC+ in the first half of 2020 that increased oil production. These factors resulted in the price of Brent crude oil reaching a historic low of just under $20 per barrel during the second quarter of 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 the year and may negatively impact future production levels due to the natural production decline of our assets. Although prices have improved, they remained below pre-pandemic levels for a prolonged period. 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 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, including because of illness, quarantines, government actions, or other restrictions in connection with the pandemic. Beginning in March 2020, we implemented workplace restrictions in response to developing government directives, including a period of several months in which most of our personnel and many of our third-party partners operated remotely. During the latter half of 2020, COVID-19 cases increased significantly nationwide and, as a result, governmental authorities implemented significant directives and restrictions, including in the state of California. We are continuing to monitor these directives where we have operations and/or offices and modify our workplace restrictions as necessary. 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 continue 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.

The extent to which the COVID-19 pandemic adversely affects our business, results of operations, and financial condition will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and future actions taken by governmental authorities and other third parties in response to the pandemic.

Our ability to operate profitably and maintain our business and financial condition are highly dependent on commodity prices, which is 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. If oil prices further decline, 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 / 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;
- 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.

In the first quarter of 2020, crude oil prices fell sharply and dramatically, due in part to significantly decreased demand as a result of the COVID-19 pandemic coupled with the increase in supply from the actions of OPEC+. Oil prices subsequently recovered but this recovery appears fragile, with oil price volatility remaining elevated and oil demand remaining below pre-COVID-19 pandemic levels. Demand, and pricing, may again decline due to the ongoing COVID-19 pandemic, particularly given the resurgence of the outbreak in the latter part of 2020 and into 2021. 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 contributed to significantly reduced economic activity and diminished expectations for the global economy. Additionally, recent acts of protest and civil unrest in the United States, including those associated with perceived racial injustice and the 2020 presidential election, have caused economic and political disruption in the United States. Meanwhile, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth and political stability have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to 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 2020, 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, which have been severely limited by recent market conditions related to the COVID-19 pandemic and the accompanying oversupply of oil and natural gas. 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 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. During the second quarter of 2020, we obtained additional storage capacity to support our planned production for the remainder of the year and into 2021. As market conditions improved, we released a portion of the capacity. However, the 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.

Storage and transportation capacity for our production is limited and may become unavailable on commercially reasonable terms or at all. 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 are unable to obtain additional storage capacity if needed, we could be forced to shut-in a significant amount of our California production, as well as curtail some of our Utah and Colorado 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 will incur additional costs to bring the associated wells back online. While production is shut in, we will likely incur additional costs and operating expenses to, among other things, maintain the health of the reservoirs, meet contractual obligations and protect our interests, but 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 the how long storage remains filled and unavailable to us, which is largely based on factors outside of our control and unpredictable.

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 (see "— Our ability to operate profitably and maintain our business and financial condition are highly dependent on commodity prices, which is 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. If oil prices further decline for a prolonged period, our business, financial condition and results of operations may be materially and adversely affected");
- 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 have subsequently increased our planned capital expenditures for 2021, lower than expected demand and prices for commodities could materially adversely affect our 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 has 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, which shortages or delays may be created or exacerbated by the effects of and governmental response to COVID-19;
- 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, 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 12% of our total net acreage at December 31, 2020.

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 2021 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 five cogeneration facilities that, combined, provide approximately 23% of our steam capacity and approximately 62% 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 three 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 2020 electricity sales decreased by $4 million, or 12%, due to lower unit sales resulting from unexpected downtime at our largest cogen during the summer when we receive peak pricing, and lower 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. 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 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.

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.

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 2021 capital expenditure budget of approximately $120 to $130 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 2021 capital expenditures with cash flows from our operations, supplemented by cash on hand which was built as excess Levered Free Cash Flow during 2020; 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.”

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 such 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. Our commodity-price risk-management activities 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, 2020, we have hedged crude oil production at the following approximate volumes and Brent prices: 15.1 MBbl/d at $45.95 per barrel in 2021. We have also hedged gas purchases at the following approximate volumes and prices: 45.6 MMbtu/d at $2.80 per in 2021.

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. The amount available to be borrowed under the RBL Facility is subject to a borrowing base, which 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. Reduction of our borrowing base under the RBL Facility could reduce the capital available to us for investment in our business. For details regarding the terms of the RBL Facility and our 2026 Notes, see "Liquidity and Capital Resources".

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.

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. 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. Currently, we have elected to limit the amount we can borrow under the RBL Facility to an amount well below our borrowing base.

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.

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.

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, 2020, sales to Marathon Petroleum, Phillips 66 and Kern Oil & Refining accounted for approximately 44%, 20% 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, 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.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to environmental protection and the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. For example, 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 plan to issue additional regulations of certain oil and natural gas activities in 2021. 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.

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. 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, 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.

Our operations in California are subject to numerous and stringent state, local and other laws and regulations that could delay or otherwise adversely impact our operations. For example, in 2019, new legislation expanded CalGEM's duties to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs, and will require CalGEM to study and prioritize controlling emissions from idle and abandoned wells, evaluate plugging and abandonment and restoration costs and associated bonding requirements. Additionally, 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) review and updating of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the Legislature in 2019; and (3) a performance audit of CalGEM's permitting processes for WST permits and PALs for underground injection by the State Department of Finance and an independent review and approval 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 a moratorium to prohibit new underground oil-extraction wells from using high-pressure cyclic steaming process. Additionally, on February 24, 2020, a California Court of Appeals effectively invalidated a Kern County ordinance that streamlined the permitting process for oil and gas exploration, extraction, operations and production activities in unincorporated Kern County, until the County makes certain revisions to the Kern County EIR supporting the ordinance and recertifies it. Other state agencies, including CalGEM, 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. To address the Kern County Ruling, Kern County has elected to prepare a supplemental EIR. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in the supplemental EIR, though it must be approved by the county Board of Supervisors before becoming effective. It is currently expected to be finalized and approved in the first half of 2021; although the timing of such approach such could be delayed, and the supplemental EIR and certification may also be subject to litigation. We cannot predict whether this supplemental EIR will result in the imposition of more onerous permit application requirements or other limits on exploration and production activities. As a result of these regulatory changes, we have experienced, and we expect to experience further, delays in obtaining drilling and other permits in California, If we are unable to obtain the required permits on a timely basis or at all, we may not be able to continue our development and production plans, and our financial and operating results could be adversely affected.

Our operations, as well as those of other exploration and production companies in areas where we operate, 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 the Order that seeks to reduce both the supply of and demand for fossil fuels in the state. The Order establishes several goals and directs 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 ending the issuance of new hydraulic fracturing permits in the state by 2024. The Order also directs CalGEM to finish its review of public health and safety concerns from the impacts of oil extraction activities and propose significantly strengthened regulations, which may include setbacks, to address these concerns by December 31, 2020, though this deadline was subsequently extended to Spring 2021. In October 2020, the Governor issued an executive order that establishes a state goal to conserve at least 30% of California’s land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity. At this time, we cannot predict how implementation of these executive orders may impact our operations. Similarly, in September 2020, Colorado published a draft “roadmap” to reduce GHG emissions from the state, including proposed actions to decarbonize transportation fleets and increase the use of renewables by electric utilities, among other things.

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 (fracking), 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. As proposed, SB 467 will also prohibit 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. The ultimate outcome of Senate Bill 467 or any other proposed legislation remains uncertain at this time, as past measures to further impose additional stringent requirements upon oil and gas activities in the California legislature were not successful. For example, in both 2019 and 2020, California considered legislation to impose a statewide setback distance between certain oil and natural gas operations and residences, schools, and healthcare facilities. However, in both cases, the proposal failed to receive the approval of the California State Senate

Our operations may also be adversely affected by seasonal or permanent restrictions on drilling activities 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 2020 we paid $18 million in asset retirement obligations, a decrease from $27 million in 2019, largely due to the new idle well regulations and our focus on environmental, health & safety ("EH&S") as we develop 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 or proposed new or more stringent requirements for permitting, well construction and public disclosure or environmental review of, or restrictions on, oil and natural gas operations. 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.

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. Similar regulations applicable to oil and gas facilities have been promulgated in Colorado.

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. 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, 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 has signed executive orders recommitting the United States to the agreement and calling for the federal government to formulate the United States' nationally determined emissions reduction target under the agreement. The impacts of these executive orders, and the terms of any legislation or regulation promulgated to implement the United States’ commitment to the Paris Agreement, are unclear at this time.

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 January 27 order also suspends the issuance of new leases for oil and gas development on federal lands to the extent permitted by law; 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. 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. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. 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.

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. Berry Corp.'s 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 regularly declared a quarterly dividend from our July 2018 IPO through the first quarter of 2020. We temporarily discontinued our quarterly dividends following the historic oil price drop and economic impact of the Covid-19 pandemic. The Company's Board of Directors declared a regular dividend of $0.04 per share on the Company's outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021. The payment and amount of future dividend payments, if any, are subject to declaration by our Board of Directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors 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 whose terms could adversely affect the voting power or value of our common stock.

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

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

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

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

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. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 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.

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

On January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. Once those motions are decided, and the court appoints a lead plaintiff and lead counsel, the lead plaintiff will likely file an amended complaint, and defendants will then move to dismiss. 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 estimate the reasonably possible loss or range of loss that may result from this action.

Environmental Matters

We received a Notice of Violation & Proposed Settlement, dated January 13, 2021, from the San Joaquin Valley Air Pollution Control District ("APCD") for purported violation of APCD Rule 2520 when we inadvertently exceeded the capacity of one of our tank vapor recovery systems in Poso Creek Field as a result of diverting production fluids and gas from a shutdown tank into another operating tank. In the notice, the APCD imposed a civil penalty in the amount of $409,650 along with an offer to negotiate a settlement. We intended to negotiate a settlement of this matter and currently expect the settlement amount to be less than the imposed penalty, however, we cannot estimate with certainty the amount of the final penalty.

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 33 stockholders of record at January 31, 2021.

Dividend Policy

We plan to use 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 dividends through commodity price cycles. We expect remaining cash flows will be allocated to fund internal growth opportunities. Our dividends 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. 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 beginning the first quarter of 2021 with the Company's Board of Directors declaring a regular dividend at a rate of $0.04 per share on the Company's outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021.

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 5.6 million have been issued or reserved through December 31, 2020.

The following table summarizes information related to our equity compensation plans under which our equity securities are authorized for issuance as of December 31, 2020.

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)]	4,520,989	N/A	4,395,440

(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

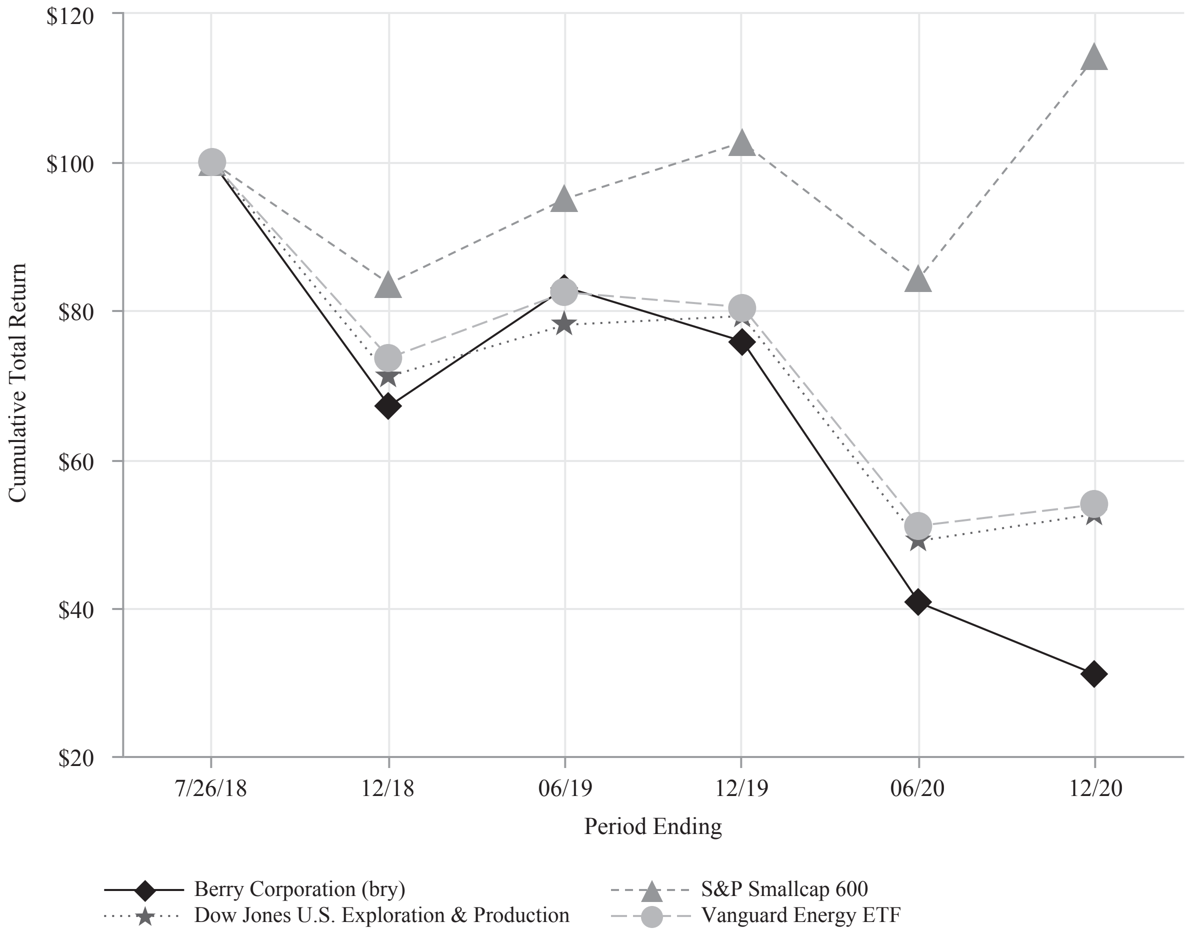
In December 2018, we announced that our Board of Directors had adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock at that time, they authorized initial repurchases of up to $50 million 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. The Company has repurchased a total of 5,057,682 shares, at an average price of $9.88 per share, under the stock repurchase program for approximately $50 million of our $100 million repurchase program. In February 2020, the Board of Directors authorized the remaining $50 million of our $100 million repurchase program. However, no additional shares have been purchased in 2020. The remaining approximate dollar value of shares that may yet be purchased under the plan is $50 million.

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
Berry Corporation (bry)	$ 100.00	$ 67.17	$ 83.16	$ 75.90	$ 40.66	$ 30.98
S&P Smallcap 600	$ 100.00	$ 83.66	$ 95.12	$ 102.72	$ 84.38	$ 114.32
Dow Jones U.S. Exploration & Production	$ 100.00	$ 71.18	$ 78.12	$ 79.29	$ 49.00	$ 52.61
Vanguard Energy ETF	$ 100.00	$ 73.67	$ 82.49	$ 80.50	$ 51.03	$ 53.89

(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

The following table shows the selected historical financial information, for the periods and as of the dates indicated, of Berry LLC, the predecessor company, and following the Effective Date, Berry Corp. and its subsidiary, Berry LLC, together, the successor company. The selected historical financial information as of and for the year ended December 31, 2020, the year ended December 31, 2019, the year ended December 31, 2018, and the ten months ended December 31, 2017 is derived from audited consolidated financial statements of the successor company. The selected historical financial information as of and for the two months ended February 28, 2017 and the year ended December 31, 2016 is derived from the audited historical financial statements of our predecessor company.

Berry LLC emerged from bankruptcy on February 28, 2017 ("the Effective Date") in connection with "the Plan", which is the reorganization plan approved and confirmed by the Bankruptcy Court in the Chapter 11 Proceeding. On that date Berry LLC adopted fresh-start accounting and was recapitalized, which resulted in Berry LLC becoming a wholly-owned subsidiary of Berry Corp. and Berry Corp. being treated as the new entity for financial reporting. As a result, our consolidated financial statements subsequent to the Effective Date are not comparable to our financial statements prior to such date. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

	Berry Corp. (Successor)				Berry LLC (Predecessor)	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands, except per share amounts)					
Statements of Operations Data:						
Revenues and other	$ 523,833	$ 559,405	$ 586,557	$ 319,669	$ 92,718	$ 410,991
Net (loss) income attributable to common stockholders(1)(2)	$ (262,895)	$ 43,539	$ 49,160	$ (39,316)	$ (502,964)	$ (1,283,196)
Net (loss) earnings per share of common stock						
Basic	$ (3.29)	$ 0.54	$ 0.85	$ (1.02)	n/a	n/a
Diluted	$ (3.29)	$ 0.53	$ 0.85	$ (1.02)	n/a	n/a
Dividends per common share	$ 0.12	$ 0.48	$ 0.21	$ —	$ —	$ —
Weighted-average common stock outstanding(3)						
Basic	79,802	81,379	57,743	38,644	n/a	n/a
Diluted(3)	79,802	81,951	57,932	38,644	n/a	n/a
Cash Flow Data:						
Operating activities(4)	$ 196,529	$ 241,829	$ 105,471	$ 107,399	$ 22,431	$ 13,197
Capital expenditures	$ (87,816)	$ (223,154)	$ (129,652)	$ (65,479)	$ (3,158)	$ (34,796)
Balance Sheet Data (at period end):						
Total assets	$ 1,419,810	$ 1,690,198	$ 1,692,263	$ 1,546,402	$ 1,561,038	$ 2,652,050
Long-term debt, net	$ 393,480	$ 394,319	$ 391,786	$ 379,000	$ 400,000	$ —

(1) Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" for discussion regarding factors in comparability, such as, impairment and income taxes in 2020 and 2019.

(2) Net Income Attributable to Common Stockholders for the year ended December 31, 2020 included a $289 million non-cash pre-tax asset impairment charge on properties in Utah and certain California locations and $61 million in discrete income tax items. Net Income

Attributable to Common Stockholders for the year ended December 31, 2019 included a $51 million non-cash impairment charge for the Piceance gas properties and $39 million in discrete income tax items.

(3) The Series A Preferred Stock was not a participating security; therefore, we calculated diluted earnings per share using the "if-converted" method, under which the preferred dividends are added back to the numerator and the Series A Preferred Stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock were included in the diluted EPS calculation for the years ended December 31, 2020, 2019 or 2018, as all outstanding shares of our Series A Preferred (the "Series A Preferred Stock") were converted to common shares (the "Series A Preferred Stock Conversion") in connection with the IPO of our common stock in July 2018. No incremental shares of Series A Preferred Stock were included in the diluted earnings per share calculation for the ten months ended December 31, 2017 as their effect was antidilutive under the "if-converted" method. Please see Note 6 for further detail.

(4) 2018 includes a one-time payment of $127 million in the second quarter to early terminate unsettled derivative contracts. The elective cancellation was effected to realign our hedging pricing with current market rates and move from WTI to Brent underlying.

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 2020 and 2019 items and year-to-year comparisons between those years. For discussion of our year ended December 31, 2018, as well as the year ended 2019 compared to year ended 2018, refer to Part II, Item 7— "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2019 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.

In the aggregate, our assets are characterized by high oil content. Most of our assets are located in the oil-rich reservoirs in the San Joaquin basin of California, which has more than 150 years of production history and substantial remaining oil in place. As a result of the substantial data produced over the basin's long history, its reservoir characteristics are well understood, leading to predictable, repeatable, low geological risk and low-cost development opportunities. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. We also have assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah and in the low geologic risk natural gas resource play in the Piceance basin in Colorado. We believe that the successful execution of our strategy across our low-declining, oil-weighted production base and 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 capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles.

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

How We Plan and Evaluate Operations

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

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

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of our business. Adjusted EBITDA is a non-GAAP financial measure that we define as earnings before interest expense; income taxes; depreciation, depletion, and amortization ("DD&A"); derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items.

Operating expenses

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

Environmental, health & safety

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

As part of our commitment to creating long-term stockholder value, we strive to conduct our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate and our other stakeholders in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with existing laws and regulations. We monitor our EH&S performance through various measures, and incentivize our employees to perform at high standards, including through our annual short-term incentive program.

General and administrative expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities and less than 10% of such costs are capitalized, which is significantly less than industry norms. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

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

Business Environment 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. As discussed below, our 2020 operating and financial results have been adversely impacted by the deterioration and prolonged weakness in commodity prices resulting from the COVID-19 pandemic and certain actions by foreign oil and gas producers. While oil prices began to improve toward the end of 2020, they remain volatile.

The extent to which our operating and financial results of future periods will be adversely impacted by the ongoing COVID-19 pandemic will depend largely on future developments, which are highly uncertain and cannot be accurately predicted. We are unable to reasonably predict when, or to what extent, commodity prices and the overall markets and global economy will stabilize, and the pace of any subsequent recovery for the oil and gas industry. Further, to what extent these events do ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors that are not within our control and cannot be predicted, including the duration and extent of the pandemic and speculation as to future actions by Saudi Arabia, Russia and other foreign producers. We have taken steps and continue to work to address the evolving challenges and mitigate mounting repercussions from both the COVID-19 pandemic and the industry downturn on our operations, our financial condition and our people. We continue to plan for a prolonged downturn well into 2021, in spite of recent slight improvements in oil prices. However, given the tremendous volatility and turmoil, there is no certainty that the measures we take will ultimately be sufficient.

The COVID-19 Pandemic and Industry Downturn

In December 2019, a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19, was reported to have surfaced in China. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic. The COVID-19 pandemic has caused significant disruption globally since January 2020 and the U.S. economy continues to experience profound effects. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains and created significant volatility and disruption of the financial and commodity markets. The oil and gas industry has been severely impacted by the steep and prolonged deterioration in the price of oil caused by the significant decrease in demand because of the COVID-19 pandemic and corresponding preventative measures taken around the world to mitigate the spread of the virus, compounded by a supply surge from Saudi Arabia and Russia in the first half of 2020.

In March 2020, OPEC+ failed to reach an agreement on production levels for crude oil, at which point Saudi Arabia and Russia aggressively increased oil production and exports. The convergence of these events - the unprecedented dual impact of a severe global oil demand decline related to the COVID-19 pandemic coupled with a substantial increase in supply - drove oil prices to historically low levels and created significant volatility, uncertainty, and turmoil in the oil and gas industry. As a result, the price of oil was extremely depressed and even reached historic lows during the second quarter 2020, with the price of Brent crude bottoming to just under $20 per Bbl in mid April 2020. These market conditions prompted producers all over the world to shut-in production and delay new oil and gas projects. OPEC+ eventually announced production cuts in April 2020, and then in June 2020 agreed to extend the cuts through the end of July 2020. In August these production cuts were eased slightly and the output reduction levels remained through the end of 2020. In December 2020 and January 2021, OPEC+ agreed to cut production slightly beginning in January 2021 and will continue to reassess monthly.

Additionally, the effects of demand destruction with a supply surge globally was amplified during the second quarter 2020 as available storage for crude oil and refined products became increasingly limited and there were concerns that available storage could become completely unavailable in 2020 and beyond, depending on the duration and severity of the ongoing pandemic. With the storage and transportation constraints further adding to the pressure on commodities prices, during the second quarter 2020 refiners started to curtail output and producers all over the world - including in the United States - started to shut-in production. Toward the end of the second quarter 2020, oil prices began to recover as the production cuts reduced the supply overhang and global demand began to increase gradually with containment of the COVID-19 outbreak in areas around the globe. The storage concerns were partially relieved as a result. Demand, and pricing, may again decline due to the ongoing COVID-19 pandemic, particularly if there is a continued resurgence of the outbreak, although the extent of the additional impact on our industry and our business cannot be reasonably predicted at this time.

As we focus 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 has been, and is, our top priority. For the protection of our employees and to help contain the spread of COVID-19, at times since the pandemic began we modified our business practices, including temporary closing of offices not required to maintain critical operations and instead allowing a large portion of our workforce to work from home, and we have implemented recommended practices with respect to social distancing, quarantines, travel bans and other restrictions. Although we managed the transition to remote work arrangements and subsequent office reopening without a loss in business continuity, we incurred additional costs and experienced some inefficiencies; importantly, none of which had an impact on our financial reporting systems, internal control over financial reporting or disclosure controls and procedures. We managed minimal workforce disruption, with no furloughs, as a result of the pandemic, in part due to the "essential" nature of our business. As discussed above, the situation remains volatile and, if there is a resurgence of the COVID-19 outbreak in our areas of operation, we may be forced to again temporarily close our offices and transition to work from home; although we currently expect our operations would continue as normal and without significant additional impact due to the essential nature of our business. We remain committed to being a good corporate citizen 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.

As a result of the industry downturn, commodity price outlook, and increasing uncertainty, on April 1, 2020, we provided updated guidance for the 2020 fiscal year, reflecting a heightened focus on driving operational efficiencies, preserving cash and reducing costs, including through reducing planned 2020 capital expenditures. We also temporarily suspended our quarterly cash dividend, starting with the second quarter of 2020, and we did not repurchase any common stock under our authorized share repurchase program during 2020.

Our California production increased slightly year-over-year, even with the limited capital deployed. While our Rockies production decreased largely due to natural declines and no drilling programs during 2020. Due to the significant drop in prices in early 2020, we temporarily discontinued our California drilling activity in April and engaged in proactive maintenance and well management activities. We restarted our drilling activity in mid-October 2020, which we currently expect to continue through 2021 if our financial position and market conditions continue to support it. Capital spending for the full year 2020 was approximately $69 million, excluding capitalized overhead and interest, acquisitions and asset retirement spending. During the second quarter of 2020, we obtained additional storage capacity to support our planned production for the remainder of the year and into 2021. As market conditions improved, we released a portion of the capacity. We currently believe our storage capacity will be sufficient to support our current planned production and we do not anticipate a need to shut in production or delay or discontinue our drilling plans in the near future unless conditions significantly deteriorate, economics dictate or storage becomes unavailable. Currently we have storage capacity of 315,000 Bbls through June of 2021 to help mitigate these potential consequences. For a discussion of certain potential risks, costs and other considerations related to storage constraints and production curtailment, please see Part I, Item 1A. Risk Factors in this report - **"*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, which have been severely limited by recent market conditions related to the COVID-19 pandemic and the accompanying oversupply of oil and natural gas. 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.*"**

Commodity Pricing and Differentials

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

Average oil prices were lower for the year ended December 31, 2020 compared to the year ended December 31, 2019. Brent crude oil contract prices ranged from $68.91 per Bbl to $19.33 per Bbl and averaged $42.10 per Bbl during the first half of 2020 and averaged $44.30 per Bbl during the second half of 2020. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. Even as Brent pricing fell, and was weak, due to the effects of demand destruction with a supply surge globally, during the second quarter of 2020, we also experienced an adverse widening in the price differential between Brent and California benchmark, caused primarily by to the lack of local demand and storage capacity. This differential contracted in the third and fourth quarters of 2020 as local demand improved and market storage concerns softened. We planned for significant deterioration of these differentials and refinery utilizations, and our plan for this expected worsening situation did not fully materialize, which enabled us to mitigate the impact. As described above, if reactions to the COVID-19 pandemic against cause demand to worsen, and/or if OPEC+ producers take actions that again create a supply surge, and if necessary storage availability is not sufficient, oil prices may again go materially lower and Brent and/or California pricing could potentially even become negative as WTI oil prices did on April 20, 2020.

In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $12.69 per MMBtu and as low as $1.25 per MMBtu during 2020, while we paid an average of $2.46 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, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
Brent oil ($/Bbl)	$ 43.21	$ 64.16
WTI oil ($/Bbl)	$ 39.59	$ 57.03
Kern, Delivered natural gas ($/MMBtu)	$ 2.46	$ 3.14
Henry Hub natural gas ($/MMBtu)	$ 2.03	$ 2.56

As mentioned above, California oil prices are Brent-influenced as California refiners import more than 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.

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

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities, than we produce and sell in Utah and Colorado ("the Rockies"). Additionally, in recent history, the California gas markets have had higher gas prices than the Rockies and the rest of the United States. Consequently, higher gas prices have a negative impact on our operating results. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. We also strive to minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of such as purchase. The negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce in the Rockies.

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by three of our cogeneration facilities under long-term contracts with terms ending in July 1, 2021 through December 1, 2026. We are currently in discussions with the counterparty with regards to the power purchase agreement ("PPA") expiring in 2021. The most significant input and cost of the cogeneration facilities is natural gas. We generally receive significantly more revenue from these cogeneration facilities in the summer months, June through September, due to negotiated capacity payments we receive.

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

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, 2020 and 2019.

	Year Ended December 31,	
	2020	2019
Average daily production:[1]		
Oil (MBbl/d)	25.0	25.3
Natural Gas (MMcf/d)	18.5	20.0
NGLs (MBbl/d)	0.4	0.4
Total (MBoe/d)[2]	28.5	29.0
Total Production:		
Oil (MBbl)	9,176	9,226
Natural gas (MMcf)	6,766	7,302
NGLs (MBbl)	131	151
Total (MBoe)[2]	10,435	10,594
Weighted-average realized prices:		
Oil without hedges ($/Bbl)	$ 39.56	$ 58.93
Effects of scheduled derivative settlements ($/Bbl)	$ 16.51	$ 4.68
Oil with hedges ($/Bbl)	$ 56.07	$ 63.61
Natural gas ($/Mcf)	$ 2.08	$ 2.66
NGLs ($/Bbl)	$ 12.57	$ 17.02
Average Benchmark prices:		
Oil (Bbl) – Brent	$ 43.21	$ 64.16
Oil (Bbl) – WTI	$ 39.59	$ 57.03
Gas (MMBtu) – Kern, Delivered[3]	$ 2.46	$ 3.14
Natural gas (MMBtu) – Henry Hub[4]	$ 2.03	$ 2.56

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

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 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,	
	2020	2019
Average daily production (MBoe/d)[1]:		
California	22.9	22.6
Utah	4.3	5.0
Colorado	1.3	1.4
Total average daily production	28.5	29.0

(1) Production represents volumes sold during the period.

Average daily oil production was essentially flat for the year ended December 31, 2020 compared to the year ended December 31, 2019. California production, which is 100% oil, was 22.9 MBoe/d for the year ended December 31, 2020 an increase of 1.3% year-over-year where the majority of our capital in 2019 and 2020 was deployed. Of the 45 California wells drilled in 2020, 34 were producing wells, nine were delineation and two were injector wells. Production levels in 2020 were also negatively impacted by the significant reduction in development capital spending compared to the prior year. The production in Utah and Colorado decreased 13% year-over-year, as very little capital was deployed in either year.

Summary by Area

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

	California (San Joaquin and Ventura basins)		Utah (Uinta basin)		Colorado (Piceance basin)	
	Year Ended December 31,		Year Ended December 31,		Year Ended December 31,	
	2020	2019	2020	2019	2020	2019
($ in thousands, unless noted otherwise)						
Oil, natural gas and natural gas liquids sales	$ 335,642	$ 498,325	$ 37,481	$ 59,383	$ 5,537	$ 7,740
Operating income (loss)(1)	$ (7,915)	$ 230,500	$ (126,289)	$ 7,624	$ (357)	$ (48,955)
Depreciation, depletion, and amortization (DD&A)	$ 130,388	$ 93,025	$ 7,058	$ 11,754	$ 324	$ 1,055
Impairment of oil and gas properties	$ 163,879	$ —	$ 125,206	$ —	$ —	$ 51,081
Average daily production (MBoe/d)	22.9	22.6	4.3	5.0	1.3	1.4
Production (oil % of total)	100%	100%	50%	54%	2%	2%
Realized sales prices:						
Oil (per Bbl)	$ 40.01	$ 60.51	$ 34.81	$ 45.72	$ 24.01	$ 52.36
NGLs (per Bbl)	$ —	$ —	$ 12.57	$ 17.08	$ —	$ —
Gas (per Mcf)	$ —	$ —	$ 2.22	$ 2.94	$ 1.87	$ 2.26
Capital expenditures(2)	$ 66,398	$ 189,648	$ 1,247	$ 10,229	$ 206	$ 603
Total proved reserves (MMBoe)	87	122	7	15	1	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.

Results of Operations

	Year Ended December 31, 2020	Year Ended December 31, 2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$ 378,663	$ 565,596	$ (186,933)	(33)%
Electricity sales	25,813	29,397	(3,584)	(12)%
Gains (losses) on oil and gas sales derivatives	117,781	(37,998)	155,779	n/a
Marketing and other revenues	1,576	2,410	(834)	(35)%
Total revenues and other	$ 523,833	$ 559,405	$ (35,572)	(6)%

Revenues and Other

Oil, natural gas and NGL sales decreased by $187 million, or 33%, to approximately $379 million for the year ended December 31, 2020 when compared to the year ended December 31, 2019. The decrease was driven by $178 million and $4 million of lower prices for oil and natural gas, respectively, and an $11 million decrease in volumes in the Rockies, offset by a $9 million increase in volumes in California.

Electricity sales which represent sales to utilities decreased by $4 million, or 12%, to approximately $26 million for the year ended December 31, 2020 when compared to the year ended December 31, 2019. The decrease was largely a result of 16% lower unit sales prices that were driven by lower natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement gains for the years ended December 31, 2020 and 2019 were $152 million and $43 million, respectively. The increase in settlement gains was driven by lower oil prices relative to the derivative fixed prices in 2020 compared to 2019. The mark-to-market non-cash loss for the years ended December 31, 2020 and 2019 of $34 million and $81 million, respectively, were due to higher future prices relative to the derivative fixed prices at each year end.

Marketing and other revenues were lower for the year ended December 31, 2020, compared to the year ended December 31, 2019 due to lower average gas prices.

	Year Ended December 31, 2020	2019	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 186,348	$ 216,294	$ (29,946)	(14)%
Electricity generation expenses	16,608	19,490	(2,882)	(15)%
Transportation expenses	6,938	8,059	(1,121)	(14)%
Marketing expenses	1,380	2,073	(693)	(33)%
General and administrative expenses	77,696	62,643	15,053	24 %
Depreciation, depletion and amortization	139,180	106,006	33,174	31 %
Impairment of oil and gas properties	289,085	51,081	238,004	466 %
Taxes, other than income taxes	35,572	40,645	(5,073)	(12)%
Losses (gains) on natural gas purchase derivatives	1,035	6,957	(5,922)	(85)%
Other operating expense (income)	5,781	4,588	1,193	26 %
Total expenses and other	759,623	517,836	241,787	47 %
Other (expenses) income:				
Interest expense	(34,295)	(34,234)	(61)	— %
Other, net	(28)	80	(108)	(135)%
Total other (expenses) income	(34,323)	(34,154)	(169)	— %
Reorganization items, net	—	(426)	426	(100)%
(Loss) income before income taxes	(270,113)	6,989	(277,102)	(3,965)%
Income tax expense (benefit)	(7,218)	(36,550)	29,332	(80)%
Net (loss) income	$ (262,895)	$ 43,539	$ (306,434)	(704)%
Adjusted EBITDA[(6)]	$ 244,430	$ 302,184	$ (57,754)	(19)%
Adjusted Net Income (Loss)[(6)]	$ 44,816	$ 110,228	$ (65,412)	(59)%
Expenses per Boe:[(1)]				
Lease operating expenses	$ 17.86	$ 20.42	$ (2.56)	(13)%
Electricity generation expenses	1.59	1.84	(0.25)	(14)%
Electricity sales	(2.47)	(2.77)	0.30	(11)%
Transportation expenses	0.66	0.76	(0.10)	(13)%
Transportation sales	(0.01)	(0.03)	0.02	(67)%
Marketing expenses	0.13	0.20	(0.07)	(35)%
Marketing revenues	(0.14)	(0.20)	0.06	(30)%
Derivative settlements paid for gas purchases[(1)]	0.89	0.10	0.79	790 %
Total operating expenses	$ 18.51	$ 20.32	$ (1.81)	(9)%
Total unhedged operating expenses[(2)]	$ 17.62	$ 20.22	$ (2.60)	(13)%
Total non-energy operating expenses[(3)]	$ 13.63	$ 14.80	$ (1.17)	(8)%
Total energy operating expenses[(4)]	$ 4.88	$ 5.51	$ (0.63)	(11)%
General and administrative expenses[(5)]	$ 7.45	$ 5.91	$ 1.54	26 %
Depreciation, depletion and amortization	$ 13.34	$ 10.01	$ 3.33	33 %
Taxes, other than income taxes	$ 3.41	$ 3.84	$ (0.43)	(11)%

(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 $1.94 per Boe and $1.08 per Boe for the year ended December 31, 2020 and December 31, 2019, 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 9% or $1.81 per Boe for the year ended December 31, 2020 from $20.32 for the year ended December 31, 2019 due to $2.56 per Boe lower lease operating expenses, partially offset by $0.79 per Boe of higher gas hedge settlement losses. Additionally, operating expenses, on an unhedged basis were $17.62 per Boe for the year ended December 31, 2020, which was 13% lower than the year ended December 31, 2019. Operating expenses are defined above in "How We Plan And Evaluate Operations."

As a result of our cost savings and efficiency initiatives implemented beginning in the second quarter of 2020, we achieved a positive and substantial impact on operating expenses in 2020 when compared to 2019 without compromising our safety standards or curtailing production to reduce costs. Through these initiatives, non-energy operating expense decreased approximately $15 million, $1.17 per Boe, when compared to the prior year. Primary year-over-year cost reductions were driven by lower outside services ($0.71 per Boe), well maintenance ($0.52) and surface facilities maintenance ($.04 per Boe). These decreases were slightly offset by our increased non-capital workover and recompletion campaign ($0.06 per Boe), which began in the fourth quarter. Energy operating expense declined $7 million, $0.63 per Boe, year-over-year due to lower hedged fuel expense of $0.93 per Boe which was partially offset by lower electricity sales of $0.30. The lower hedged fuel expense was largely due to lower prices, as well as a 3% year-over-year reduction in daily fuel consumption, saving $0.20 per Boe. Average purchase price of natural gas in 2020 was $2.55 MMbtu, down from $3.18 in the prior year. Notional volumes for our gas purchase hedges averaged 59,200 MMBtu/d and 46,000 MMBtu/d in 2020 and 2019, respectively, whereas the fixed contract prices remained unchanged at $2.92 year to year.

Electricity generation expenses decreased 14% to $1.59 per Boe for the year ended December 31, 2020 from $1.84 for the year ended December 31, 2019 primarily driven by lower fuel cost. Decreased 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, 2020 and 2019 were losses of $1 million and $7 million, respectively. The settlement loss for the year ended December 31, 2020 was $9 million, or $0.89 per Boe, compared to a settlement loss of $1 million, or $0.10 per Boe for same period in 2019, consistent with the changes in futures prices at the end of each period. The mark-to-market valuation gain or loss for each of the years ended December 31, 2020 and December 31, 2019 was a gain of $8 million and a loss of $6 million, respectively.

Transportation expenses decreased 13% to $0.66 per Boe for the year ended December 31, 2020, compared to $0.76 for the year ended December 31, 2019, mainly due to lower volumes shipped from our Rockies assets.

Marketing expenses decreased 35% to $0.13 per Boe for the year ended December 31, 2020, compared to $0.20 per Boe for the year ended December 31, 2019 due to lower 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 increased by approximately $15 million or 24%, for the year ended December 31, 2020 compared to the year ended December 31, 2019. This increase is a result of $9 million of non-cash stock compensation and non-recurring costs, as well as $6 million of adjusted general and administration expenses noted below. For the year ended December 31, 2020 and 2019, general and administrative expenses included non-cash stock compensation costs of approximately $14 million and $8 million, respectively, and non-recurring costs of approximately $6 million and $3 million, respectively. Non-recurring costs in 2020 mainly consisted of employee reorganization and termination costs and to a lesser degree costs associated with the volatile and depressed price environment. In 2019, these costs primarily were temporary professional services for our transition to a stand-alone company as well as to a public company.

Adjusted general and administrative expenses, which excluded non-cash compensation costs and non-recurring costs, were $57 million for the year ended December 31, 2020 compared to $51 million for the year ended December 31, 2019. The year-over-year increases in adjusted general and administrative expenses were primarily due to higher employee compensation and increased activities necessary in a heavily regulated industry for our participation in the regulatory, political and legislative process primarily in California. 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 $33 million, or 31%, to approximately $139 million, for the year ended December 31, 2020 compared to the year ended December 31, 2019, due to the higher depreciation and depletion rates for 2020. On a per Boe basis, year-over-year DD&A increased $3.33 to $13.34 from $10.01 due to our extensive 2019 capital development program and to a lesser degree that of early 2020.

Impairment of Oil and Gas Properties

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. 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 $28 million for unproved properties.

Taxes, Other Than Income Taxes

	Year Ended December 31,			
	2020	2019	$ Change	% Change
	(per Boe)			
Severance taxes	$ 0.77	$ 0.63	$ 0.14	22 %
Ad valorem taxes	1.62	1.38	0.24	17 %
Greenhouse gas allowances	1.02	1.83	(0.81)	(44)%
Total taxes other than income taxes	$ 3.41	$ 3.84	$ (0.43)	(11)%

Taxes, other than income taxes, decreased $0.43 to $3.41 per Boe for the year ended December 31, 2020 compared to $3.84 for the year ended December 31, 2019. The decrease was largely due to lower greenhouse gas prices during 2020 including some allowance purchases we made at low prices due to a temporary market dislocation in the first quarter of 2020, as well as lower CO_2 emissions. During 2020, we experienced higher property tax rates, as well as higher severance tax rates due to the expiration of certain deductions.

Other Operating Expense (Income)

For the years ended December 31, 2020 and 2019 other operating expenses were $6 million and $5 million, respectively. These other operating expenses 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. Additionally in 2020, as a result of the drastic and abrupt change to the oil supply and demand environment, we incurred additional costs for added oil tank storage capacity and drilling rig standby charges, partially offset by tax and other refunds from prior years received in 2020.

Interest Expense

Interest expense was comparable for the years ended December 31, 2020 and 2019.

Reorganization Items, Net

Reorganization items, net were not material for the year ended December 31, 2020 and year ended December 31, 2019.

Income Tax Expense (Benefit)

For the years ended December 31, 2020 and 2019, we had income tax benefits of approximately $7 million and $37 million, respectively. The key contributors to the change in our effective tax 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 US federal general business credits in 2019 related to the 2017 and 2018 tax periods. The credits recorded in 2019 are available to offset future federal income tax liabilities. 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 capital expenditures with cash flows from our operations, supplemented in 2021 by cash on hand resulting from the excess Levered Free Cash Flow we generated during 2020. As of December 31, 2020, we had liquidity of $273 million, consisting of $80 million cash in the bank and borrowing availability of $193 million under our RBL Facility (excluding $7 million in stand-by letters of credit). 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 November 2020, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants noted below. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms. We currently believe that our liquidity, capital resources and cash on hand will be sufficient to conduct our business and operations for at least the next 12 months.

We currently expect our operations to continue to generate positive Levered Free Cash Flow for the combined two-year down-cycle through the end of 2021 at the current oil price levels, based on our current operating plans and current hedge positions. We currently have oil sales hedges of approximately 19,000 Bbls/d at nearly $46 per barrel in the first half of 2021 and approximately 14,000 Bbls/d in the second half of 2021 at $49 per barrel. However, our business, like other producers, has been and is expected to continue to be negatively affected by the ongoing and evolving volatility, uncertainty, and turmoil in the oil and gas industry created by the COVID-19 demand destruction and the unknown supply levels caused by OPEC+'s actions, as further discussed under "Business Environment and Market Conditions" in this report. We may potentially use Levered Free Cash Flow to opportunistically repurchase the 2026 Notes, to explore accretive acquisitions that would strengthen our asset base or to fund our 2021 capital expenditures in the event there is insufficient operating cash flow.

In the longer term, if depressed oil prices were to persist through 2021 and longer, we may not be able to continue to generate the same level of Levered Free Cash Flow we are currently generating and our liquidity and capital resources may not be sufficient to conduct our business and operations in the longer term until commodity prices recover. In light of continuing uncertainty, negative commodity price outlook, and significant risks mentioned above and further discussed elsewhere in this report (including under Part I, Item 1.A. “Risk Factors”), we continue to plan for a prolonged downturn and our strategy to survive is focused on preserving cash, reducing costs and maintaining business continuity. We temporarily suspended our quarterly cash dividend, starting with the second quarter of 2020, and we did not repurchase any common stock under our authorized share repurchase program in 2020. We did declare a quarterly dividend in the first quarter of 2021, subject to ongoing quarterly determination by the Company's Board of Directors. The Board declared a regular dividend at a rate of $0.04 per share on the Company’s outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021. Although we continue to actively work to mitigate the evolving challenges of this severe industry downturn on our operations, our financial condition and our employees and contractors, there is no certainty that the measures we take will ultimately be sufficient. We are unable to reasonably predict when, or to what extent, commodity prices and the overall markets and global economy will stabilize, and the pace of any subsequent recovery for the oil and gas industry. Further, to what extent these events do ultimately impact our business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous evolving factors that cannot be predicted, including the severity and duration of the COVID-19 pandemic and future actions by OPEC+.

The RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“RBL Facility”). The RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. The RBL Facility has an elected commitment feature that allows us to increase commitments to the amount of our borrowing base with lender approval. In November 2020, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants noted below; certain anti-cash hoarding provisions, including the requirement to repay outstanding loans on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $30 million; and further limits to dividends and share repurchases. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral.

The outstanding borrowings under the RBL Facility bear interest at a rate equal to either (i) a customary London interbank offered rate plus an applicable margin ranging from 2.5% to 3.5% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.5% to 2.5% per annum, 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 RBL Facility. We have the right to prepay any borrowings under the RBL Facility with prior notice at any time without a prepayment penalty, other than customary “breakage” costs with respect to euro-dollar loans.

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of December 31, 2020, our Leverage Ratio and Current Ratio were 1.8:1.0 and 2.2:1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of December 31, 2020.

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

Berry Corp. guarantees and each future subsidiary of Berry Corp. (other than Berry LLC), with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the RBL Facility and under certain hedging transactions and banking services arrangements (the “Guaranteed Obligations”). In addition, pursuant to a Guaranty Agreement dated as of July 31, 2017, Berry LLC guarantees the Guaranteed Obligations. The lenders under the RBL Facility hold a mortgage on 85% 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. The RBL Facility, with certain exceptions, also requires that any future subsidiaries of Berry LLC will also have to grant mortgages, security interests and equity pledges.

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 used a portion of the net proceeds from the issuance of the 2026 Notes to repay the $379 million outstanding balance on the RBL Facility and used the remainder for general corporate purposes.

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. We are also entitled to redeem up to 35% of the aggregate principal amount of the 2026 Notes before February 15, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107% of the principal amount of the 2026 Notes being redeemed, plus accrued and unpaid interest, if any. In addition, prior to February 15, 2021, we may redeem some or all of the 2026 Notes at a price equal to 100% of the principal amount thereof, plus a “make-whole” premium, plus any accrued and unpaid interest. 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 (other than Berry LLC). 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.

Bond Repurchase Program

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

Corporate Organization

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

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

Hedging

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including through fixed-price derivative contracts. We hedge crude oil and gas production to protect against oil and gas price decreases and we also hedge gas purchases to protect against price increases. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. We expect our operations to generate sufficient cash flows at current commodity prices including our 2021 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 December 31, 2020, we had the following crude oil production and gas purchases hedges.

	Q1 2021	Q2 2021	Q3 2021	Q4 2021
Fixed Price Oil Swaps (Brent):				
Hedged volume (MBbls)	1,710	1,728	1,042	1,042
Weighted-average price ($/Bbl)	$ 45.82	$ 45.82	$ 46.17	$ 46.17
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	4,950,000	4,777,500	4,830,000	2,085,000
Weighted-average price ($/MMBtu)	$ 2.69	$ 2.83	$ 2.83	$ 2.95

As of December 31, 2020 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 MMBtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period January 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of $2.6 million. This gain will be cash settled in 2021 as the positions expire

In February 2021, we added 3,000 Bbls/d of fixed price oil swaps (Brent) at approximately $58 for the period July 2021 through December 31, 2021.

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

	Year Ended December 31,	
	2020	2019
Crude Oil (per Bbl):		
Realized sales price, before the effects of derivative settlements	$ 39.56	$ 58.93
Effects of derivative settlements	$ 16.51	$ 4.68
Realized sales price, after the effects of derivative settlements	$ 56.07	$ 63.61
Purchased Natural Gas (per MMBtu):		
Purchase price, before the effects of derivative settlements	$ 2.55	$ 3.18
Effects of derivative settlements	$ 0.35	$ 0.04
Purchase price, after the effects of derivative settlements	$ 2.90	$ 3.22

Cash Dividends

Our Board of Directors approved a $0.12 per share quarterly cash dividend on our common stock for the first quarter of 2020, which we paid in April 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 reinstituted a quarterly dividend in the first quarter of 2021, subject to future determination by the Company's Board of Directors. The Board declared a regular dividend at a rate of $0.04 per share on the Company’s outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021. As of December 31, 2020 we have paid approximately $65 million in dividends on our common stock since our IPO in July 2018.

Capital Program

For the years ended December 31, 2020 and December 31, 2019 our capital expenditures were approximately $69 million and $209 million, respectively, on an accrual basis excluding capitalized overhead and interest, acquisitions and asset retirement spending.

The decrease in capital expenditures year over year was due to the reduction of our planned 2020 capital expenditures by approximately 50% from our original 2020 guidance towards the end of the first quarter of 2020 in response to the sudden and significant oil and gas price deterioration caused by the COVID-19 pandemic, coupled with OPEC+ actions, which created significant volatility, uncertainty, and turmoil in the oil and gas industry. During the second and third quarters of 2020, capital expenditures were focused on continuing our permitting and proactive maintenance activities to support ongoing activity and safe operations. We proactively initiated an intense permitting program during the first quarter 2020 to ensure adequate inventory once we restarted our drilling program. We restarted our drilling program in mid-October 2020 and increased workover and recompletion projects during the fourth quarter 2020. The 2020 capital expenditures included approximately $24 million for facilities and cogen projects, including long-term maintenance, as well as approximately $38 million for drilling, completions and equipping.

Nearly all of the 2020 capital was dedicated to California activity. California production increased slightly more than 1% year-over-year even with the significant reduction in our capital program.

Our currently anticipated 2021 capital expenditure budget is approximately $120 to $130 million, which we expect will result in flat year-over-year production and a higher exit rate for 2021 than the beginning of the year. We currently anticipate oil production will be approximately 89% of total production volume in 2021, compared to 88% in 2020 and 87% in 2019. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2021 capital development programs with cash flow from operations and current cash on hand, which was generated during 2020 and anticipated for use to supplement our 2021 capital program. We currently expect to employ up to three drilling rigs in California during 2021. Additionally, we currently expect to drill approximately 170 to 200 development wells and 10 to 15 delineation wells during 2021, all of which are anticipated to be in California for oil production. The execution of these plans requires regulatory permits and approvals, and changes in laws and regulations, including those relating to the permit review and approval process, could impact our ability to successfully execute our plans. Please see “Regulation of Health, Safety and Environmental Matters” for additional discussion.

The amount and timing of capital expenditures are within our control and subject to our management’s discretion, and may be adjusted during the year depending on commodity prices, storage constraints, supply/demand considerations and other factors. We retain the flexibility to defer planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the receipt and timing of required regulatory permits and approvals, the availability of necessary equipment, infrastructure and capital, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners, as well as general market conditions.

In addition to capital expenditures, we also incur costs associated with retiring assets and remediating property at the end of its useful life, both due to regulatory obligations and our focus on EH&S as we develop existing fields. Most of these obligations and activities are regulated by governmental agencies. We spent approximately $18 million on plugging and abandonment activities, exceeding our annual obligations requirements under the California Idle Well Management Program, and in 2021 we expect to spend approximately $19 million to $23 million for such activities

Acquisitions

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 the California Idle Well Management Program. We recorded a $6 million liability for asset retirement obligations of the existing wells on this property.

In 2020 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.

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 at such time. The Company repurchased a total of 5,057,682 shares at an average price of $9.88 per share under the stock repurchase program for approximately $50 million in 2018 and 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. For the year ended December 31, 2020, we did not repurchase any shares under the stock repurchase program.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Net cash:		
Provided by operating activities	$ 196,529	$ 241,829
Used in investing activities	(93,620)	(225,025)
Used in financing activities	(22,352)	(85,484)
Net increase (decrease) in cash and cash equivalents	$ 80,557	$ (68,680)

Operating Activities

Cash provided by operating activities decreased for the year ended December 31, 2020 by approximately $45 million when compared to the year ended December 31, 2019, due to decreased sales of $191 million, and increased cash general and administrative expenses of $9 million. These decreases were partially offset by increased derivative settlements received of $100 million, decreased lease operating expenses and electricity generation expenses of $33 million, decreased taxes, other than income taxes of $5 million, and working capital changes of $16 million.

Investing Activities

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

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Capital expenditures (1)		
Capital expenditures	$ (76,480)	$ (211,995)
Changes in capital expenditures accruals	(11,336)	(11,159)
Acquisition of properties and equipment and other	(5,981)	(2,840)
Proceeds from sale of properties and equipment and other	177	969
Cash used in investing activities:	$ (93,620)	$ (225,025)

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

Cash used in investing activities decreased $131 million for the year ended December 31, 2020 when compared to the year ended December 31, 2019, primarily due to a decrease in capital spending in response to the sudden and significant oil and gas price deterioration in early 2020, which created significant volatility, uncertainty, and turmoil in the oil and gas industry.

Financing Activities

Cash used in financing activities was approximately $22 million for the year ended December 31, 2020 and decreased by approximately $63 million from the year ended December 31, 2019. The decrease is primarily due to treasury stock purchases of $47 million in 2019 and none in 2020. Additionally, we paid fewer dividends in 2020 by approximately $20 million, since the Company's Board of Directors termporarily suspsended the resgular quarterly dividend in the second quarter of 2020. Partially offsetting the positive cash impact of these activities, we reduced our net borrowings by approximately $4 million on the RBL Facility in 2020 compared to 2019.

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 reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at December 31, 2020 and December 31, 2019. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of December 31, 2020, we are not aware of material indemnity claims pending or threatened against us.

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

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of December 31, 2020:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:					
Processing, transportation and storage contracts[(1)]	$ 7,910	$ 4,104	$ 3,806	$ —	$ —
Operating lease obligations	11,106	1,863	3,650	3,102	2,491
Other purchase obligations[(2)]	35,100	18,000	17,100	—	—
Total	$ 54,116	$ 23,967	$ 24,556	$ 3,102	$ 2,491

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

(2) Amounts include a purchase commitment of $6 million to build a road, which is classified as current. Additionally, we have a drilling commitment in California, for which we are required to drill 97 wells with an estimated total cost of $29 million by April 2023 and 40 of those wells are estimated at $12 million and are required to be drilled by December 2021.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2019 to December 31, 2020 are discussed below.

	December 31, 2020		December 31, 2019	
	(in thousands)			
Cash and cash equivalents	$	80,557	$	—
Accounts receivable, net	$	52,027	$	71,867
Derivative instruments assets - current and long-term	$	2,507	$	9,691
Other current assets	$	19,400	$	19,399
Property, plant & equipment, net	$	1,258,084	$	1,576,267
Other non-current assets	$	7,235	$	12,974
Accounts payable and accrued expenses	$	151,985	$	151,811
Derivative instruments liabilities - current and long-term	$	23,321	$	4,958
Long-term debt	$	393,480	$	394,319
Deferred income taxes liability - long-term	$	1,011	$	9,057
Asset retirement obligation - long-term	$	135,192	$	124,019
Other non-current liabilities	$	785	$	33,586
Stockholders' equity	$	714,036	$	972,448

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

The $20 million decrease in accounts receivable was driven mostly by lower sales, both price and volume, period-over-period, partially offset by higher hedge settlements outstanding in 2020.

The $26 million decrease in net derivative assets and liabilities is due to the change from a net asset of $5 million in 2019 to a net liability of $21 million in 2020. 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 $318 million decrease in property, plant and equipment was largely the result of the $289 million impairment on our oil and gas properties in the first quarter of 2020, as well as depreciation expense of $129 million, partially offset by capital investments of $69 million, $14 million of acquisitions, including capitalized interest and overhead, and $16 million for asset retirement obligations.

The $6 million decrease in other non-current assets was primarily due to deferred debt issuance cost amortization.

The changes in accounts payable and accrued expenses included an increase of approximately $36 million of greenhouse gas liability as the entire amount is due in the fourth quarter of 2021, offset by $17 million of decreased accruals and spending for various capital and operating costs due to the reduced level of these costs in 2020, $10 million fewer royalties accrued due to decreased sales, and the $10 million impact of dividends accrued at the end of 2019 with no corresponding accrual at December 31, 2020.

The decrease in long-term deferred income taxes liability is due to the income tax benefit during the year.

The $11 million increase in the long-term portion of the asset retirement obligation from $124 million at December 31, 2019 to $135 million at December 31, 2020 was due to revised cost estimates of $10 million, $10 million of accretion and $6 million of liabilities incurred. These increases were partially offset by $15 million of liabilities settled during the period.

The $33 million decrease in other non-current liabilities was due to the non-current greenhouse gas liability entire amount coming due in the fourth quarter of 2021 and thus classified as a current liability in accounts payable and accrued expenses as of December 31, 2020.

The $258 million decrease in stockholders' equity was due to the net loss of $263 million and $10 million of common stock dividends declared. These decreases were partially offset by $15 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 other unusual, out-of-period and infrequent items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

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

Adjusted Net Income (Loss) excludes the impact of unusual, out-of-period and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, 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, out of period 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,	
	2020	2019
	(in thousands)	
Adjusted EBITDA reconciliation to net income (loss):		
Net (loss) income	$ (262,895)	$ 43,539
Add (Subtract):		
Interest expense	34,295	34,234
Income tax expense (benefit)	(7,218)	(36,550)
Depreciation, depletion, and amortization	139,180	106,006
Impairment of oil and gas properties	289,085	51,081
(Gains) losses on derivatives	(116,746)	44,955
Net cash received for scheduled derivative settlements	142,292	42,197
Other operating expenses	5,781	4,588
Stock compensation expense	14,630	8,647
Non-recurring costs	6,026	3,061
Reorganization items, net	—	426
Adjusted EBITDA	$ 244,430	$ 302,184

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Adjusted EBITDA reconciliation to net cash provided by operating activities and Levered Free Cash Flow calculation:		
Net cash provided by operating activities	$ 196,529	$ 241,829
Add (Subtract):		
Cash interest payments	29,962	30,720
Cash income tax payments (refunds)	222	(2)
Non-recurring costs	6,026	3,061
Other changes in operating assets and liabilities	11,691	26,576
Adjusted EBITDA	$ 244,430	$ 302,184
Subtract:		
Capital expenditures - accrual basis(1)	(69,120)	(208,770)
Interest expense	(34,295)	(34,234)
Cash dividends declared	(9,564)	(39,053)
Levered Free Cash Flow(2)	$ 131,451	$ 20,127

(1) Capital expenditures on an accrual basis excludes capitalized overhead and interest and acquisitions. Also excluded is asset retirement spending of $18.1 million and $26.9 million for the years ended December 31, 2020 and 2019, respectively.

(2) Levered Free Cash Flow includes cash received for scheduled derivative settlements of $142 million and $42 million for the years ended December 31, 2020 and 2019.

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,	
	2020	2019
	(in thousands)	
Adjusted Net Income (Loss) reconciliation to net (loss) income:		
Net (loss) income	$ (262,895)	$ 43,539
Add (Subtract): discrete income tax items	61,030	(38,653)
Add (Subtract):		
(Gains) losses on derivatives	(116,746)	44,955
Net cash received for scheduled derivative settlements	142,292	42,197
Other operating expenses	5,781	4,588
Impairment of oil and gas properties	289,085	51,081
Non-recurring costs	6,026	3,061
Reorganization items, net	—	426
Total additions (subtractions), net	326,438	146,308
Income tax expense of adjustments at effective tax rate(1)	(79,757)	(40,966)
Adjusted Net Income (Loss)	$ 44,816	$ 110,228
Basic EPS on Adjusted Net Income	$ 0.56	$ 1.35
Diluted EPS on Adjusted Net Income	$ 0.56	$ 1.35
Weighted average shares outstanding - basic	79,802	81,379
Weighted average shares outstanding - diluted	79,902	81,951

(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,	
	2020	2019
	(in thousands)	
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:		
General and administrative expenses	$ 77,696	$ 62,643
Subtract:		
Non-cash stock compensation expense (G&A portion)	(14,264)	(8,356)
Non-recurring costs	(6,026)	(3,061)
Adjusted general and administrative expenses	$ 57,406	$ 51,226
Adjusted general and administrative expenses ($/MBoe)	$ 5.50	$ 4.84

Off-Balance Sheet Arrangements

See "—**Liquidity and Capital Resources**—*Commitments, and Contingencies*" and "—*Contractual Obligations* " for information regarding our off-balance sheet arrangements.

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 $0.60 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, 2020 and 2019, the net capitalized costs attributable to unproved properties was approximately $311 million and $314 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, 2020.

As of March 31, 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 during the latter part of the first quarter. These declines were driven by the uncertainty surrounding the outbreak of a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19 and other macroeconomic events such as the geopolitical tensions between the OPEC and Russia. The COVID-19 pandemic and related economic repercussions, coupled with actions taken by OPEC and other oil producing nations ("OPEC+"), created significant volatility, uncertainty, and turmoil in the oil and gas industry, which have negatively affected and are expected to continue to negatively affect our business.

Consequently, 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. 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 believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance December 31, 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 $28 million for unproved properties.

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 vest based on our achievement of certain average prices per share or total shareholder return, to certain employees and non-employee directors. The fair value of the stock-based awards is determined at the date of grant and is not remeasured. Prior to our IPO in July 2018, we determined the fair value of the RSUs based on an estimate of the fair value of our equity using an income approach. We used a discounted cash flow method to value the estimated future cash flows at an appropriate discount rate. Subsequent to our IPO, since the underlying shares are now trading in the public markets, these estimates are no longer necessary. For PSUs, compensation value is measured on the grant date using payout values derived from a Monte-Carlo valuation model. 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

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the periods discussed. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we may experience inflationary pressure on the cost of oilfield services and equipment as increasing oil, natural gas and NGL prices increase drilling activity in our areas of operations. An increase in oil, natural gas and NGL prices may cause the costs of materials and services to rise.

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 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 impact of current, pending and/or future laws and regulations, and of legislative and regulatory changes and other government activities, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- the length, scope and severity of the ongoing COVID-19 pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, and storage capacity;
- global economic trends, geopolitical risks and general economic and industry conditions, such as these 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; including the sharp decline in crude oil prices that occurred in the first quarter and second quarter of 2020;
- the California and global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;
- supply of and demand for oil, natural gas and NGLs;
- disruptions to, capacity constraints in, or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures, meet our working capital requirements or fund planned investments;
- price fluctuations and availability of natural gas and electricity and the cost of steam;
- our ability to use derivative instruments to manage commodity price risk;
- availability or timing of, or conditions imposed on, permits and approvals;
- the regulatory environment, including availability or timing of, and conditions imposed on, obtaining and/or maintaining permits and approvals, including those necessary for drilling and/or development projects;

- our ability to meet our planned drilling schedule, including due to our ability to obtain permits on a timely basis or at all, and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- concerns about climate change and other air quality issues;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- drilling and production results, lower–than–expected production, reserves or resources from development projects or higher–than–expected decline rates;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;
- changes in tax laws;
- effects of competition;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including wildfires, earthquakes and pandemics;
- environmental risks and liabilities under federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyber attacks.
- 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 further significant decline.

We have hedged a large portion of our expected crude oil production and our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls and puts to hedge. We do not enter into derivative contracts for speculative trading purposes and we have not accounted for our derivatives as cash-flow or fair-value hedges. We continuously consider the level of our oil production and gas purchases that 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, 2020, the fair value of our hedge positions was a net liability of approximately $21 million. A 10% increase in the oil and natural gas index prices above the December 31, 2020 prices would result in a net liability of approximately $38 million; conversely, a 10% decrease in the oil and natural gas index prices below the December 31, 2020 prices would result in a net asset of approximately $11 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 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 nine commodity derivative counterparties at December 31, 2020 and seven at December 31, 2019. 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, the RBL Facility prevents us from entering into hedging arrangements that are secured (except with our lenders and their affiliates), that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from 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, 2020 was not material and losses associated with credit risk have not been been material for all periods presented.

Interest Rate Risk

Our RBL Facility has a variable interest rate on outstanding balances. As of December 31, 2020, we had no borrowings under our RBL Facility and thus we have 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 its subsidiary (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, 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
February 24, 2021

BERRY CORPORATION (bry)
CONSOLIDATED BALANCE SHEETS

	December 31, 2020	December 31, 2019
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80,557	$ —
Accounts receivable, net of allowance for doubtful accounts of $2,215 at December 31, 2020 and $1,103 at December 31, 2019	52,027	71,867
Derivative instruments	2,507	9,166
Other current assets	19,400	19,399
Total current assets	154,491	100,432
Noncurrent assets:		
Oil and natural gas properties	1,412,566	1,675,717
Accumulated depletion and amortization	(235,259)	(209,105)
Total oil and natural gas properties, net	1,177,307	1,466,612
Other property and equipment	112,145	135,117
Accumulated depreciation	(31,368)	(25,462)
Total other property and equipment, net	80,777	109,655
Derivative instruments	—	525
Other noncurrent assets	7,235	12,974
Total assets	$ 1,419,810	$ 1,690,198
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 151,985	$ 151,811
Derivative instruments	23,321	4,817
Total current liabilities	175,306	156,628
Noncurrent liabilities:		
Long-term debt	393,480	394,319
Derivative instruments	—	141
Deferred income taxes	1,011	9,057
Asset retirement obligation	135,192	124,019
Other noncurrent liabilities	785	33,586
Commitments and Contingencies - Note 5		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 85,041,581 and 84,655,222 shares issued; and 79,929,335 and 79,542,976 shares outstanding, at December 31, 2020 and December 31, 2019, respectively)	85	85
Additional paid-in capital	915,877	901,830
Treasury stock, at cost (5,112,246 shares at December 31, 2020 and at December 31, 2019)	(49,995)	(49,995)
Retained (deficit) earnings	(151,931)	120,528
Total stockholders' equity	714,036	972,448
Total liabilities and stockholders' equity	$ 1,419,810	$ 1,690,198

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2020	2019	2018
	(in thousands, except per share amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 378,663	$ 565,596	$ 552,874
Electricity sales	25,813	29,397	35,208
Gains (losses) on oil and gas sales derivatives	117,781	(37,998)	(4,621)
Marketing revenues	1,426	2,094	2,322
Other revenues	150	316	774
Total revenues and other	523,833	559,405	586,557
Expenses and other:			
Lease operating expenses	186,348	216,294	188,776
Electricity generation expenses	16,608	19,490	20,619
Transportation expenses	6,938	8,059	9,860
Marketing expenses	1,380	2,073	2,140
General and administrative expenses	77,696	62,643	54,026
Depreciation, depletion and amortization	139,180	106,006	86,271
Impairment of oil and gas properties	289,085	51,081	—
Taxes, other than income taxes	35,572	40,645	33,117
Losses (gains) on natural gas purchase derivatives	1,035	6,957	(6,357)
Other operating expense (income)	5,781	4,588	(2,747)
Total expenses and other	759,623	517,836	385,705
Other (expenses) income:			
Interest expense	(34,295)	(34,234)	(35,648)
Other, net	(28)	80	243
Total other (expenses) income	(34,323)	(34,154)	(35,405)
Reorganization items, net	—	(426)	24,690
(Loss) income before income taxes	(270,113)	6,989	190,137
Income tax expense (benefit)	(7,218)	(36,550)	43,035
Net (loss) income	(262,895)	43,539	147,102
Series A Preferred Stock dividends and conversion to common stock	—	—	(97,942)
Net (loss) income attributable to common stockholders	$ (262,895)	$ 43,539	$ 49,160
Net (loss) earnings per share attributable to common stockholders:			
Basic	$ (3.29)	$ 0.54	$ 0.85
Diluted	$ (3.29)	$ 0.53	$ 0.85

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Series A Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained (Deficit) Earnings	Total Equity
			(in thousands)			
December 31, 2017	$ 335,000	$ 33	$ 545,345	$ —	$ (21,068)	$ 859,310
Cash dividends declared on Series A Preferred Stock, $0.308/share	—	—	(11,301)	—	—	(11,301)
Conversion of Series A Preferred Stock into common stock	(335,000)	40	334,960	—	—	—
Cash payment to Series A Preferred Stockholders	—	—	(60,273)	—	—	(60,273)
Issuance of common stock in initial public offering	—	10	133,795	—	—	133,805
Repurchase of common stock	—	(2)	(23,710)	—	—	(23,712)
Shares withheld for payment of taxes on equity awards	—	1	(3,700)	—	—	(3,699)
Stock based compensation	—	—	6,789	—	—	6,789
Purchase of rights to common stock	—	—	—	(20,265)	—	(20,265)
Purchase of treasury stock	—	—	—	(3,953)	—	(3,953)
Dividends declared on common stock, $0.21/share	—	—	(7,365)	—	(9,992)	(17,357)
Net income	—	—	—	—	147,102	147,102
December 31, 2018	—	82	914,540	(24,218)	116,042	1,006,446
Shares withheld for payment of taxes on equity awards	—	—	(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 and other	—	—	(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

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

BERRY CORPORATION (bry)
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Cash flow from operating activities:			
Net (loss) income	$ (262,895)	$ 43,539	$ 147,102
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	139,180	106,006	86,271
Amortization of debt issuance costs	5,351	5,059	5,430
Impairment of oil and gas properties	289,085	51,081	—
Stock-based compensation expense	14,630	8,647	6,750
Deferred income taxes	(8,045)	(36,778)	43,946
Increase (decrease) in allowance for doubtful accounts	1,112	153	(20)
Other operating expenses (income)	5,083	5,518	(2,747)
Reorganization expenses, net (non-cash)	—	—	(25,523)
Derivatives activities:			
Total (gains) losses	(116,746)	44,955	(1,735)
Cash settlements on derivatives	142,292	42,197	(38,482)
Cash payments on early-terminated derivatives	—	—	(126,949)
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	18,767	(14,597)	(1,683)
Increase in other assets	(2)	(5,136)	(819)
Increase (decrease) in accounts payable and accrued expenses	(14,172)	(917)	19,526
Decrease in other liabilities	(17,111)	(7,898)	(5,596)
Net cash provided by operating activities	196,529	241,829	105,471
Cash flow from investing activities:			
Capital expenditures:			
Capital expenditures	(76,480)	(211,995)	(150,023)
Changes in capital expenditures accruals	(11,336)	(11,159)	20,371
Acquisition of properties and equipment and other	(5,981)	(2,840)	—
Proceeds from sale of property and equipment and other	177	969	8,212
Net cash used in investing activities	(93,620)	(225,025)	(121,440)
Cash flow from financing activities:			
Borrowings under RBL credit facility	228,900	355,132	203,510
Repayments on RBL credit facility	(230,750)	(353,282)	(582,510)
Dividends paid on common stock	(19,463)	(39,157)	(7,365)
Purchase of treasury stock	—	(46,909)	(23,351)
Shares withheld for payment of taxes on equity awards and other	(1,039)	(1,268)	(3,699)
Issuance of 2026 Senior Unsecured Notes	—	—	400,000
Debt issuance costs	—	—	(9,193)
IPO proceeds net of issuance costs	—	—	133,805
Repurchase of common stock	—	—	(23,712)
Payment to preferred stockholders in conversion	—	—	(60,273)
Dividends paid on Series A Preferred Stock	—	—	(11,301)
Net cash (used in) provided by financing activities	$ (22,352)	$ (85,484)	$ 15,911
Net increase (decrease) in cash, cash equivalents and restricted cash	80,557	(68,680)	(58)
Cash, cash equivalents and restricted cash:			
Beginning	—	68,680	68,738
Ending	$ 80,557	$ —	$ 68,680

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

Note 1—Basis of Presentation and Significant Accounting Policies

Effective February 18, 2020, Berry Petroleum Corporation changed its name to Berry Corporation (bry) and introduced a new logo. We believe that the name Berry Corporation (bry) is a name that better represents our progressive approach to evolving and growing the business in today's dynamic oil and gas industry.

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

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

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law in February 2017 and its common stock began trading on NASDAQ under the symbol "bry" in July 2018. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located onshore in the United States (the "U.S."), in California (in the San Joaquin and Ventura basins), Utah (in the Uinta basin), and Colorado (in the Piceance basin).

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.

Reclassification

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

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 $1 million in 2020, $2 million in 2019, and in 2018 these costs were not significant. 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 $6 million, $2 million and $1 million in 2020, 2019 and 2018, respectively.

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 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, 2020 and 2019, the net capitalized costs attributable to unproved properties was approximately $311 million and $314 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.

As of March 31, 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 during the latter part of the first quarter. These declines were driven by the uncertainty surrounding the outbreak of a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19 ("COVID-19") and other macroeconomic events such as the geopolitical tensions between the Organization of Petroleum Exporting Countries ("OPEC") and Russia. The COVID-19 pandemic and related economic repercussions, coupled with actions taken by OPEC and other oil producing nations ("OPEC+"), created significant volatility, uncertainty, and turmoil in the oil and gas industry, which have negatively affected and are expected to continue to negatively affect our business.

Consequently, 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. 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 believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance December 31, 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 $28 million for unproved properties.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, cogeneration facilities, buildings, 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 5 to 30 years for buildings and leasehold improvements and 2 to 30 years for plant and pipeline, drilling and other equipment, and the salvage value is considered as applicable.

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 was 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 $135 million and $124 million were included in long term liabilities as of December 31, 2020 and December 31, 2019, respectively, with the remaining current portion included in accrued liabilities:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in thousands)	
Beginning balance	$ 149,227	$ 95,548
Liabilities incurred including from acquisitions	5,919	11,534
Settlements and payments	(14,931)	(22,036)
Accretion expense	9,996	7,570
Revisions	9,981	56,611
Ending balance	$ 160,192	$ 149,227

A majority of the revisions during 2019 was a result of California's new idle well regulations which became effective in the second quarter of that year and accelerated the timing of abandonment of certain long existing idle wells. The revisions in 2020 largely reflected further changes to timing and cost estimates of these abandonment projects.

Revenue Recognition

Substantially all of the Company's revenue is from the sale of crude oil, natural gas and NGLs. 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 most significant items on our balance sheet that would be affected by recurring fair value measurements are 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.

Our 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. 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 vest based on our achievement of certain average prices per share or total shareholder return, to certain employees and non-employee directors. The fair value of the stock-based awards is determined at the date of grant and is not remeasured. Prior to our IPO in July 2018, we determined the fair value of the RSUs based on an estimate of the fair value of our equity using an income approach. We used a discounted cash flow method to value the estimated future cash flows at an appropriate discount rate. Subsequent to our IPO, since the underlying shares are now trading in the public markets, these estimates are no longer necessary. For PSUs, compensation value is measured on the grant date using payout values derived from a Monte-Carlo valuation model. 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 bases. 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 and preferred stock 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 also 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. Based on the current demand for oil, natural gas and NGLs 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, 2020, our three largest customers represented approximately 44%, 20% and 12% of our sales. For the year ended December 31, 2019, our three largest customers represented 36%, 24%, and 13% of our sales. For the year ended December 31, 2018, our three largest customers represented approximately 35%, 28% and 13% of our sales.

At December 31, 2020, trade accounts receivable from three customers represented approximately 38%, 15%, and 11% of our receivables. At December 31, 2019, trade accounts receivable from three customers represented approximately 40%, 17% and 11% of our receivables.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers. 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 are currently identifying our lease population in accordance with the new lease standard. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and we are currently evaluating the impact on our consolidated results of operations.

In December 2019, the FASB issued rules which simplify the accounting for income taxes. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We are currently evaluating the impact of these rules on our consolidated financial statements.

In March 2020, the FASB issued rules providing 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, 2020	Year Ended December 31, 2019
	(in thousands)	
Proved properties	$ 1,101,371	$ 1,361,814
Unproved properties	311,195	313,903
Total proved and unproved properties	1,412,566	1,675,717
Less accumulated depletion and amortization	(235,259)	(209,105)
Total proved and unproved properties, net	$ 1,177,307	$ 1,466,612

Other Property and Equipment

Other property and equipment consisted of the following:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in thousands)	
Cogens, natural gas plants and pipelines	$ 72,999	$ 94,619
Buildings and leasehold improvements	2,241	3,752
Vehicles and service equipment	8,878	9,124
Furniture and equipment	21,515	20,078
Land	6,512	7,544
Total other property and equipment	112,145	135,117
Less: accumulated depreciation	(31,368)	(25,462)
Total other property and equipment, net	$ 80,777	$ 109,655

Note 3—Debt

The following table summarizes our outstanding debt:

	December 31, 2020	December 31, 2019	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ 1,850	variable rates of 4.0% (2020) and 5.5% (2019), respectively	July 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	401,850			
Less: Debt Issuance Costs	(6,520)	(7,531)			
Long-Term Debt, net	$ 393,480	$ 394,319			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At December 31, 2020 and December 31, 2019, debt issuance costs for the RBL Facility (as defined below) reported in “other noncurrent assets” on the balance sheet were approximately $7 million and $11 million, net of amortization, respectively. At December 31, 2020 and 2019, 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 $7 million and $8 million, respectively.

For the years ended December 31, 2020, 2019, and 2018, the amortization expense for both the RBL Facility and 2026 Notes was approximately $5 million for all periods. 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 the RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 Notes was approximately $337 million and $376 million at December 31, 2020 and 2019, respectively.

The RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“RBL Facility”). The RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $25 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the RBL Facility on a dollar for dollar basis. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. The RBL Facility has an elected commitment feature that allows us to increase commitments to the amount of our borrowing base with lender approval. In November 2020, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a reaffirmed borrowing base and the Company's elected commitment at $200 million with no further borrowing restrictions beyond the covenants noted below.

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

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of December 31, 2020, our Leverage Ratio and Current Ratio were 1.8:1.0 and 2.2:1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of December 31, 2020.

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

Berry Corp. guarantees and each future subsidiary of Berry Corp. (other than Berry LLC), with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the RBL Facility and under certain hedging transactions and banking services arrangements (the “Guaranteed Obligations”). In addition, pursuant to a Guaranty Agreement dated as of July 31, 2017, Berry LLC guarantees the Guaranteed Obligations. The lenders under the RBL Facility hold a mortgage on 85% 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. The RBL Facility, with certain exceptions, also requires that any future subsidiaries of Berry LLC will also have to grant mortgages, security interests and equity pledges.

The outstanding borrowings under the RBL Facility bear interest at a rate equal to either (i) a customary London interbank offered rate plus an applicable margin ranging from 2.5% to 3.5% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.5% to 2.5% per annum, 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 RBL Facility. We have the right to prepay any borrowings under the RBL Facility with prior notice at any time without a prepayment penalty, other than customary “breakage” costs with respect to euro-dollar loans.

As of December 31, 2020, we had no borrowings outstanding, $7 million in letters of credit outstanding, and approximately $193 million of available borrowings capacity under the RBL Facility.

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 used a portion of the net proceeds from the issuance of the 2026 Notes to repay the $379 million outstanding balance on the RBL Facility and used the remainder for general corporate purposes.

We may, at our option, redeem all or a portion of the 2026 Notes at any time on or after February 15, 2021. We were also entitled to redeem up to 35% of the aggregate principal amount of the 2026 Notes before February 15, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107% of the principal amount of the 2026 Notes being redeemed, plus accrued and unpaid interest, if any. In addition, prior to February 15, 2021, we may redeem some or all of the 2026 Notes at a price equal to 100% of the principal amount thereof, plus a “make-whole” premium, plus any accrued and unpaid interest. 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 (other than Berry LLC). 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, 2020.

Bond Repurchase Program

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

Corporate Organization

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

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

Note 4—Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted oil and gas production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices, which addresses our market risk. We target covering our operating expenses and a majority of our fixed charges, which includes capital needed to sustain production levels, as well as interest and dividends as applicable, with the oil and gas sales hedges for a period of up to two years out. Additionally, we target fixing the price for a large portion of our natural gas purchases used in our steam operations for up to two years. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations, which we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

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

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

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

As of December 31, 2020, we had the following crude oil production and gas purchases hedges.

	Q1 2021	Q2 2021	Q3 2021	Q4 2021
Fixed Price Oil Swaps (Brent):				
Hedged volume (MBbls)	1,710	1,728	1,042	1,042
Weighted-average price ($/Bbl)	$ 45.82	$ 45.82	$ 46.17	$ 46.17
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	4,950,000	4,777,500	4,830,000	2,085,000
Weighted-average price ($/MMBtu)	$ 2.69	$ 2.83	$ 2.83	$ 2.95

As of December 31, 2020 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 MMBtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period January 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of $2.6 million. This gain will be cash settled in 2021 as the positions expire

In February 2021, we added 3,000 Bbls/d of fixed price oil swaps (Brent) at approximately $58 for the period July 2021 through December 31, 2021.

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, 2020 and 2019:

	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)

	December 31, 2019			
	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	$ 17,799	$ (8,633)	$ 9,166
Commodity Contracts	Non-current assets	773	(248)	525
Liabilities:				
Commodity Contracts	Current liabilities	(13,450)	8,633	(4,817)
Commodity Contracts	Non-current liabilities	(389)	248	(141)
Total derivatives		$ 4,733	$ —	$ 4,733

In May 2018, we elected to terminate outstanding commodity derivative contracts for all WTI oil swaps and certain WTI/Brent basis swaps for July 2018 through December 2019 and all WTI oil sold call options for July 2018 through June 2020. Termination costs totaled approximately $127 million and were calculated in accordance with a bilateral agreement on the cost of elective termination included in these derivative contracts; the present value of the contracts using the forward price curve as of the date termination was elected. No penalties were charged as a result of the elective termination. Concurrently, Berry Corp. entered into commodity derivative contracts consisting of Brent oil swaps for July 2018 through March 2019.

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

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

Gains (Losses) on Derivatives

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

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Gains (losses) on oil and gas sales derivatives	$ 117,781	$ (37,998)	$ (4,621)
(Losses) gains on natural gas purchase derivatives	(1,035)	(6,957)	6,357
Total gains (losses) on derivatives	$ 116,746	$ (44,955)	$ 1,735

For the years ended December 31, 2020 and 2019, we received net cash scheduled settlements of approximately $142 million and $42 million, respectively. For the year ended December 31, 2018, we paid net cash settlements of approximately $38 million, excluding the payments for the early terminated derivatives.

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 reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at December 31, 2020 and December 31, 2019. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of December 31, 2020, we are not aware of material indemnity claims pending or threatened against us.

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

Securities Litigation Matter

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

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

Other Commitments

In addition, we entered into certain firm commitments to secure transportation of our natural gas production to market as well as processing and storage capacity 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 \$1.5 million, \$1.5 million and \$1.2 million in 2020, 2019 and 2018, respectively. At December 31, 2020, 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:

	2021	2022	2023	2024	2025	Thereafter	Total
				(in thousands)			
Processing, transportation and storage contracts[1]	$ 4,104	$ 2,588	$ 1,218	$ —	$ —	$ —	$ 7,910
Operating lease obligations	1,863	1,872	1,778	1,551	1,551	2,491	11,106
Other purchase obligations[2]	18,000	14,700	2,400	—	—	—	35,100
Total	$ 23,967	$ 19,160	$ 5,396	$ 1,551	$ 1,551	$ 2,491	$ 54,116

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

(2) Amounts include a purchase commitment of \$6 million to build a road, which is classified as current. Additionally, we have a drilling commitment in California, for which we are required to drill 97 wells with an estimated total cost of \$29 million by April 2023 and 40 of those wells are estimated at \$12 million and are required to be drilled by December 2021.

Note 6—Stockholders' Equity

On the Effective Date (as defined in Note 13), Berry Corp. filed with the Secretary of State of the State of Delaware the Amended and Restated Certificate of Incorporation of Berry Corp. (the "Certificate of Incorporation") and the Certificate of Designation of Series A Convertible Preferred Stock of Berry Corp. (the "Series A Certificate of Designation"). Berry Corp. also adopted the Amended and Restated Bylaws of Berry Corp. (the "Bylaws") on the Effective Date. The Certificate of Incorporation provides that Berry Corp.'s authorized capital stock consists of 750,000,000 shares of common stock, par value \$0.001 per share, and 250,000,000 shares of undesignated preferred stock, par value \$0.001 per share.

Cash Dividends

Our Board of Directors approved a \$0.12 per share cash dividend for the first quarter of 2020. 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. 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. For the year ended December 31, 2018, we declared cash dividends on our common stock beginning at our IPO, resulting in $0.21 per share and paid approximately $7 million in cash dividends on our common stock.

We reinstated a quarterly dividend beginning the first quarter of 2021, subject to future determination by the Company's Board of Directors. The Company's Board of Directors declared a regular dividend of $0.04 per share on the Company's outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021.

Common Stock

On the Effective Date, 32,920,000 shares of common stock in Berry Corp. were distributed in accordance with the Plan (as defined in Note 13). 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, subject to the rights of the holders of outstanding preferred stock, 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.

Holders of preferred stock that is outstanding may be entitled to dividend or liquidation preferences over holders of our common stock, which means that the Company would have to pay distributions to holders of preferred stock before paying any distributions to holders of our common stock.

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

Preferred Stock

On the Effective Date, we issued 35,845,001 shares of preferred stock to participants in the rights offerings extended by the Company to certain holders of claims and in satisfaction of a backstop commitment fee for proceeds of $335 million. In July 2018, all shares of our Series A Preferred Stock, approximately 37.7 million in total, were converted to approximately 39.6 million common shares and, as a result, there were no shares of our Series A Preferred Stock outstanding as of December 31, 2020 and 2019.

Dividend Rights. Holders of Series A Preferred Stock were entitled to receive, when, as and if declared by the board of directors, cumulative dividends at a rate of 6.0% per annum either in cash or in additional shares of Series A Preferred Stock at the discretion of the board of directors.

Also in 2018, the board approved $0.308 per share, or approximately $11.3 million in cash dividends on the Series A Preferred Stock.

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.

Initial Public Offering of Common Stock

In July 2018, we completed our IPO and as a result, on July 26, 2018, our common stock began trading on the NASDAQ under the ticker symbol BRY. We received approximately $110 million of net proceeds, after deducting underwriting discounts and offering expenses payable by us, for the 8,695,653 shares of common stock issued for our benefit in the IPO, net of the shares sold for the benefit of certain selling stockholders. The price to the public for the shares sold in our IPO was $14.00 per share. See “—Use of IPO proceeds” below for additional information.

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock was automatically converted into 1.05 shares of our common stock or 39.6 million shares in aggregate and the right to receive a cash payment of $1.75 (the “Series A Preferred Stock Conversion”). The cash payment was reduced in respect of any cash dividend paid by the Company on such share of Series A Preferred Stock for any period commencing on or after April 1, 2018. Because we paid the second quarter preferred dividend of $0.15 per share in June, the cash payment for the conversion was reduced to $1.60 per share, or approximately $60 million. In connection with the IPO, we assigned the additional 1.9 million shares of common stock issued in the Series A Preferred Stock Conversion a value of $14.00 per share, which was equal to the value of shares sold in the IPO. This approximate $27 million value and the $60 million conversion cash payment reduced the income attributable to common stockholders by approximately $87 million for the year ended December 31, 2018.

Shares Outstanding

As of December 31, 2020, there were 79,929,335 shares of common stock outstanding. Up to an additional 4,520,989 shares were issuable for unvested restricted stock units and performance restricted stock units under the Company's 2017 Omnibus Incentive Plan as of December 31, 2020.

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 at such time. The Company repurchased a total of 5,057,682 shares at an average price of $9.88 per share under the stock repurchase program for approximately $50 million in 2018 and 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. For the year ended December 31, 2020, we did not repurchase any shares under the stock repurchase program.

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 that vest if the Company's stock price reaches certain levels over defined periods of time and (ii) awards with a market objective measured against both absolute total stockholder return (“Absolute TSR”) and a relative total stockholder return (“Relative TSR”) to the Vanguard World Fund - Vanguard Energy ETF index (the “Index”) over the performance period, assuming the reinvestment of dividends. Depending on the results achieved during the two or three-year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 200% of the PSUs granted.

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

As of July 2018, the fair value of our common stock underlying our stock-based compensation awards granted was no longer based on complex models using inputs and assumptions, but rather is based on the price of our stock at the date of grant.

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 4,395,440 as of December 31, 2020.

For the years ended December 31, 2020, 2019, and 2018 the stock-based compensation expense was approximately $15 million, $9 million, and $7 million, respectively. For the years ended December 31, 2020, 2019 and 2018 the stock-based compensation had an income tax benefit of approximately zero, zero and $1.5 million, respectively.

The table below summarizes the activity relating to RSUs issued under the Restated Incentive Plan during the year ended December 31, 2020. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at December 31, 2020 was approximately $9 million which will be recognized over a weighted-average period of approximately two years.

	Number of shares	Weighted-average Grant Date Fair Value
	(shares in thousands)	
Non-vested at December 31, 2019	1,014	$ 12.05
Granted	1,850	$ 6.32
Vested	(595)	$ 11.16
Forfeited	(330)	$ 8.14
Non-vested at December 31, 2020	1,939	$ 7.52

The table below summarizes the activity relating to the PSUs issued under the Revised Incentive Plan during the year ended December 31, 2020. Unrecognized compensation cost associated with the PSUs at December 31, 2020 is approximately $14 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, 2019	798	$ 10.77
Granted	1,328	$ 15.89
Vested	(5)	$ 11.33
Forfeited	(469)	$ 11.20
Non-vested at December 31, 2020	1,652	$ 14.77

Use of IPO Proceeds

Of the approximately $110 million of net proceeds received by us in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility. This included the $60 million we borrowed on the RBL Facility to make the payment due to the holders of our Series A Preferred Stock in connection with the conversion of preferred stock to common stock. We used the remainder for general corporate purposes.

In connection with the IPO, on July 17, 2018, we entered into stock purchase agreements with certain funds affiliated with Oaktree Capital Management and Benefit Street Partners, pursuant to which we purchased an aggregate of 410,229 and 1,391,967 shares of our common stock, respectively, or 1,802,196 in total. In addition to the 8,695,653 shares of common stock issued and sold for our benefit in the IPO, we simultaneously received $24 million for selling 1,802,196 shares to the public and paid $24 million to purchase 1,802,196 shares under the stock purchase agreements. We purchased the shares immediately following the closing of the IPO and retired and returned them to the status of authorized but unissued shares. The selling stockholders also directly sold an additional 2,545,630 shares at a price to the public of $14.00 per share for which we did not receive any proceeds.

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.

We expensed approximately $1.0 million, $1.7 million, and $1.4 million for the years ended December 31, 2020, 2019, and 2018, respectively, under the provisions of the 401(k) plan.

Note 8—Income taxes

The COVID-19 pandemic and related economic repercussions, coupled with OPEC+ actions, created significant volatility, uncertainty, and turmoil in the oil and gas industry, which negatively affected our business in 2020. As a result, after evaluating the positive and negative evidence, we determined that it was more likely than not that our tax credits recorded in 2019 and other deferred tax assets would not be realized. Accordingly, we recognized a valuation allowance on our deferred tax assets for the year ended December 31, 2020 in the amount of $78 million. 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.

The key contributor to the change in our effective rate from 23% in the year ended December 31, 2018 to (523)% for the year ended December 31, 2019 is due to the recognition of U.S. federal general business credits in 2019 and are related to the 2017 and 2018 tax periods. These credits are available to offset future federal income tax liabilities.

Income tax expense (benefit) consisted of the following:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Current taxes:			
Federal	$ —	$ —	$ (465)
State	828	227	(446)
Total current taxes	828	227	(911)
Deferred taxes:			
Federal	2,653	(36,756)	33,227
State	(10,699)	(21)	10,719
Total deferred taxes	(8,046)	(36,777)	43,946
Total current and deferred taxes	$ (7,218)	$ (36,550)	$ 43,035

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

	Year Ended December 31,		
	2020	2019	2018
Federal statutory rate	21.0 %	21.0 %	21.0 %
State, net of federal tax benefit	6.3 %	8.9 %	6.3 %
Effect of permanent differences	(0.6)%	0.2 %	(0.6)%
Tax credits - Prior Year	4.9 %	(546.4)%	— %
Tax credits - Current Year	1.1 %	— %	— %
State return to provision	(1.1)%	(6.6)%	— %
Change in valuation allowance	(28.8)%	— %	(4.1)%
Effective tax rate	2.8 %	(522.9)%	22.6 %

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

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 21,205	$ 14,542
Accruals	14,208	12,218
Asset retirement obligations	43,518	41,382
Derivative instruments	5,654	—
Tax credits	62,058	47,803
Interest limitation carryforward	—	13,892
Other	4,946	5,154
Subtotal	151,589	134,991
Valuation allowance	(77,923)	—
Total deferred tax assets	73,666	134,991
Deferred tax liabilities:		
Book tax differences in property basis	(74,677)	(143,896)
Derivative instruments	—	(152)
Total deferred tax liabilities	(74,677)	(144,048)
Net deferred tax liability	$ (1,011)	$ (9,057)

As of December 31, 2020, the Company had approximately $96 million of federal net operating loss ("NOL") carryforwards and $20 million of state NOL carryforwards. The federal net operating loss carryovers have no expiration date. State net operating loss carry forwards will expire in varying amounts beginning after taxable year ended 2027. In addition, as of December 31, 2020, the Company had US federal general business tax credit carryforwards totaling $51 million and state tax credits of $14 million ($11 million net of federal benefit), which, if unused, will expire after taxable years ended 2037 and 2032, respectively.

During 2020, the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act") and the Consolidated Appropriations Act of 2021 (the "CAA") were signed into law. The CARES Act provides relief to corporate taxpayers by permitting a five-year carryback of 2018-2020 Net Operating Losses ("NOLs"), removing the 80% limitation on the utilization of those NOLs, increasing the Section 163(j) 30% limitation on interest expense deductibility to 50% of adjusted taxable income for 2019 and 2020, and accelerates refunds for minimum tax credit carryforwards, along with a few other provisions. Both the CARES Act and CAA did not have a material impact to our consolidated financial statements and related disclosures.

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Unrecognized tax benefits - January 1	$ 13,892	$ —
Prior year - change	(13,892)	6,720
Current year - change	—	7,172
Unrecognized tax benefits - December 31	$ —	$ 13,892

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 as of December 31, 2020.

We had no material uncertain tax positions at December 31, 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 2017 through 2020 federal and state tax returns 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,	
	2020	2019
	(in thousands)	
Prepaid expenses	$ 3,592	$ 4,577
Materials and supplies	11,666	10,544
Oil inventories	3,490	3,432
Other	652	846
Total other current assets	$ 19,400	$ 19,399

Other non-current assets at December 31, 2020 and December 31, 2019 included approximately $7 million and $11 million of deferred financing costs, net of amortization, respectively.

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

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Accounts payable-trade	$ 11,055	$ 13,986
Accrued expenses	43,452	57,078
Royalties payable	15,150	25,385
Greenhouse gas liability - current portion	35,554	—
Taxes other than income tax liability	10,118	9,150
Accrued interest	10,783	10,500
Dividends payable	—	9,888
Asset retirement obligation - current portion	25,000	25,208
Other	873	616
Total accounts payable and accrued expenses	$ 151,985	$ 151,811

We reclassified certain accrued expenses to accounts payable trade accounts for the prior period to conform to the current year presentation. These reclassifications had no impact on the financial statements.

At December 31, 2020 we had no non-current greenhouse gas liability as the entire amount is due in 2021 and thus classified as a current liability in accounts payable and accrued expenses. At December 31, 2019 other non-current liabilities included approximately $33 million of greenhouse gas liability.

Supplemental Information on the Statement of Operations

For the years ended December 31, 2020 and 2019 other operating expenses were $6 million and $5 million, respectively. These other operating expenses 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. Additionally in 2020, as a result of the drastic and abrupt change to the oil supply and demand environment, we incurred additional costs for added oil tank storage capacity and drilling rig standby charges, partially offset by tax and other refunds from prior years received in 2020. For the year ended December 31, 2018 other operating income was $3 million, which consisted of a gain from the sale of our East Texas property, partially offset by a loss on the settlement of asset retirement obligations, largely due to a change in timing of the retirements.

Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2020	2019	2018
		(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	$ 1,596	$ 10,056	$ 2,371
Supplemental Disclosures of Cash Payments (Receipts):			
Interest, net of amounts capitalized	$ 29,962	$ 30,720	$ 19,761
Income taxes payments (refunds)	$ 222	$ (2)	$ (1,901)
Reorganization items, net	$ —	$ —	$ 832

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

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Beginning of Period			
Cash and cash equivalents	$ —	$ 68,680	$ 33,905
Restricted cash	—	—	34,833
Cash, cash equivalents and restricted cash	$ —	$ 68,680	$ 68,738
Ending of Period			
Cash and cash equivalents	$ 80,557	$ —	$ 68,680
Restricted cash	—	—	—
Cash, cash equivalents and restricted cash	$ 80,557	$ —	$ 68,680

Restricted cash was associated with cash reserved to settle claims with general unsecured creditors prior to 2020. 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, which amounts are immaterial for these periods, for accounting purposes in the accounts payable and accrued expenses account.

Note 10—Acquisitions and Divestitures

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 the California Idle Well Management Program. 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.

2018

Disposition of East Texas Properties

On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin for approximately $7 million, before purchase price adjustments, which resulted in a gain of approximately $4 million. Production comprised approximately 0.7 MBoe per day of natural gas in the third quarter of 2018.

Acquisition of Chevron North Midway-Sunset

In April 2018, we acquired 2 leases on an aggregate of 214 acres of land owned by Chevron U.S.A. in the north Midway-Sunset field immediately adjacent to assets we currently operate. We assumed a drilling commitment of approximately $35 million to drill 115 wells on or before April 1, 2020, which we extended to April 1, 2023. We drilled 18 wells of these wells as of December 31, 2020. We paid no other consideration for the acquisition. Our drilling commitment will be tolled for a month for each consecutive 30-day period for which the posted price of WTI is less than $45 per barrel. This transaction is consistent with our business strategy to investigate areas beyond our known productive areas.

Note 11—Earnings Per Share

We calculate basic (loss) earnings per share by dividing net (loss) income attributable to common stockholders by the weighted-average number of common shares outstanding for each period presented. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, are considered common shares outstanding and are included in the computation of net income (loss) per share. Our initial capitalization included the issuance of 32,920,000 shares of common stock and another 7,080,000 shares reserved to settle claims of unsecured creditors, all of which were included in our computation of net income (loss) per share until the claims were settled and the shares issued. In March 2019, we finalized settlement of these claims, issuing approximately 2,770,000 shares. In 2019, we retrospectively adjusted the year ended December 31, 2018 weighted average shares in our earnings per share calculations for the ultimate shares issued, instead of the 7,080,000 shares that had been reserved.

In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock (see Note 6). The conversion was characterized as an induced conversion that required a deduction in our EPS calculation, from net income, of approximately $87 million in determining income attributable to common stockholders. This deduction represents the excess of fair value of the total consideration given to preferred stockholders in the transaction over the fair value of the common stock issuable under the original conversion terms. Included in the $87 million is a $60 million cash payment and approximately $27 million of value from the 1.9 million additional common shares received by preferred stockholders as a result of the automatic conversion that occurred in conjunction with our IPO.

The Series A Preferred Stock was not a participating security, therefore, we calculated diluted EPS using the "if-converted" method under which the preferred dividends are added back to the numerator and the convertible preferred stock is assumed to be converted at the beginning of the period. No incremental shares of Series A Preferred Stock were included in the diluted EPS calculation for the years ended December 31, 2020 and 2019 as all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO of our common stock in July 2018. No Series A Preferred Stock were included in the diluted EPS calculations for the year ended December 31, 2018 as their effect was anti-dilutive under the "if-converted" method.

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 year ended December 31, 2020. The incremental RSU and PSU shares of 572,000 for the year ended December 31, 2019, and the incremental RSU shares of 189,000 for the year ended December 31, 2018 were included in the diluted EPS calculation for those respective years, as their effect was dilutive under the "if-converted" method. No PSUs were included in the EPS calculations for the year end December 31, 2018 due to their contingent nature.

	Year Ended December 31,		
	2020	2019	2018
	(in thousands except per share amounts)		
Basic EPS calculation			
Net (loss) income	$ (262,895)	$ 43,539	$ 147,102
less: Series A Preferred Stock dividends and conversion to common stock	—	—	(97,942)
Net (loss) income attributable to common stockholders	$ (262,895)	$ 43,539	$ 49,160
Weighted-average shares of common stock outstanding(1)	79,802	81,379	57,743
Basic (loss) earnings per share	$ (3.29)	$ 0.54	$ 0.85
Diluted EPS calculation			
Net (loss) income	$ (262,895)	$ 43,539	$ 147,102
less: Series A Preferred Stock dividends and conversion to common stock	—	—	(97,942)
Net (loss) income attributable to common stockholders	$ (262,895)	$ 43,539	$ 49,160
Weighted-average shares of common stock outstanding(1)	79,802	81,379	57,743
Dilutive effect of potentially dilutive securities	—	572	189
Weighted-average common shares outstanding - diluted(2)	79,802	81,951	57,932
Diluted (loss) earnings per share	$ (3.29)	$ 0.53	$ 0.85

(1) In 2019 we retrospectively adjusted the year ended December 31, 2018 weighted average shares in our earnings per share calculations for the 2,770,000 shares issued instead of 7,080,000 shares that had been reserved.

(2) We excluded 101,000 RSUs and PSUs from the diluted weighted-average common shares outstanding for the year ended December 31, 2020, because their effect was anti-dilutive.

Note 12—Revenue Recognition

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

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

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

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

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.

Electricity Sales

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

Marketing Revenue

Marketing revenue primarily includes our activities associated with transporting and marketing third-party volumes. These sales are made under the same agreements with the same purchaser as our natural gas sales discussed above. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Revenues are presented excluding costs incurred prior to transferring control of these volumes to the customer, or the costs to purchase these volumes when we are acting as the principal. The revenues and expenses related to the sale and purchase of third-party volumes are presented separately as marketing revenue and marketing expenses on the 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,		
	2020	2019	2018
		(in thousands)	
Oil sales	$ 362,976	$ 543,634	$ 520,979
Natural gas sales	14,041	19,391	26,244
Natural gas liquids sales	1,646	2,571	5,651
Electricity sales	25,813	29,397	35,208
Marketing revenues	1,426	2,094	2,322
Other revenues	150	316	774
Revenues from contracts with customers	406,052	597,403	591,178
Gains (losses) on oil and gas sales derivatives	117,781	(37,998)	(4,621)
Total revenues and other	$ 523,833	$ 559,405	$ 586,557

Note 13—Emergence from Voluntary Reorganization under Chapter 11

On May 11, 2016 our predecessor company filed bankruptcy. On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding (the “Plan”). Berry LLC settled all intercompany claims against it's former parent company (pre-Effective Date) and its affiliates pursuant to a settlement agreement approved as part of the Plan and the confirmation order. The settlement agreement provided Berry LLC with a $25 million general unsecured claim against the former parent company which Berry LLC has fully-reserved. On February 28, 2017 (the “Effective Date”), the Plan became effective and was implemented. On that date Berry LLC adopted fresh-start accounting and was recapitalized, which resulted in Berry LLC becoming a wholly-owned subsidiary of Berry Corp. and Berry Corp. being treated as the new entity for financial reporting. A final decree closing the Chapter 11 Proceeding was entered September 28, 2018, with the Court retaining jurisdiction as described in the confirmation order and without prejudice to the request of any party–in–interest to reopen the case including with respect to certain, immaterial remaining matters.

GAAP requires that the financial statements, for periods subsequent to filing of the bankruptcy proceedings, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, gains and losses that are realized or incurred in connection with the bankruptcy proceedings are recorded in “reorganization items, net” on our consolidated statements of operations.

Liabilities Subject to Compromise

The holders of unsecured claims against Berry LLC, (other than the Unsecured Notes) (the “Unsecured Claims”) received a right to their pro-rated share of either (i) 7,080,000 shares of common stock in Berry Corp. or (ii) in the event that such holder irrevocably elected to receive a cash recovery, cash distributions from the Cash Distribution Pool. After the Effective Date we have negotiated with claimants to settle their claims. Through the claims resolution process, many claims were disallowed by the Bankruptcy Court because they were duplicative, amended or superseded by later filed claims, were without merit, or were otherwise overstated. Throughout the Chapter 11 proceedings, the Debtors also resolved many claims through settlements or by Bankruptcy Court orders following the filing of an objection. As a result, in early 2019, we issued 2,770,000 shares to settle these claims for which we had originally reserved 7,080,000 shares. We settled all liabilities subject to compromise through cash recovery as of

December 31, 2018, resulting in a significant recognition of gains due to the return of undistributed funds. See "Reorganization Items, net" below.

Reorganization Items, Net

Reorganization items, net represents costs and income directly associated with the Chapter 11 proceedings since the Petition Date, and also includes adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined.

The following table summarizes the components of reorganization items included in the consolidated statements of operations:

	Year Ended December 31,		
	2020	2019	2018
	(in thousands)		
Return of undistributed funds from cash distribution pool[1]	$ —	$ —	$ 22,855
Gains on resolution of pre-emergence liabilities and claims	—	—	3,713
Legal and other professional advisory fees	—	(426)	(3,083)
Other	—	—	1,205
Reorganization items, net	$ —	$ (426)	$ 24,690

(1) This amount was reclassed from restricted cash to general cash, thus does not represent a cash transaction.

BERRY CORPORATION (bry)
SUPPLEMENTAL QUARTERLY FINANCIAL DATA
(Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
2020:				
Oil, natural gas and natural gas liquid sales	$ 122,098	$ 70,515	$ 92,239	$ 93,811
Electricity sales	$ 5,461	$ 4,884	$ 8,744	$ 6,724
Gains (losses) on oil and gas derivatives	$ 211,229	$ (42,267)	$ (11,564)	$ (39,617)
Marketing revenues	$ 453	$ 292	$ 330	$ 351
Other revenues	$ 24	$ 29	$ —	$ 97
Total expenses(1)	$ 419,290	$ 112,295	$ 102,409	$ 125,629
Total other expenses	$ (8,926)	$ (8,682)	$ (8,394)	$ (8,321)
Net loss	$ (115,300)	$ (64,901)	$ (18,864)	$ (63,830)
Net loss per share:				
Basic	$ (1.45)	$ (0.81)	$ (0.24)	$ (0.80)
Diluted	$ (1.45)	$ (0.81)	$ (0.24)	$ (0.80)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
2019:				
Oil, natural gas and natural gas liquid sales	$ 131,102	$ 136,908	$ 141,250	$ 156,336
Electricity sales	$ 9,729	$ 5,364	$ 7,460	$ 6,844
Gains (losses) on oil derivatives	$ (65,239)	$ 27,276	$ 45,509	$ (45,544)
Marketing revenues	$ 830	$ 414	$ 413	$ 437
Other revenues	$ 117	$ 104	$ 40	$ 55
Total expenses(1)	$ 114,853	$ 116,886	$ 113,008	$ 173,089
Total other (expenses) income	$ (8,651)	$ (8,961)	$ (8,674)	$ (7,868)
Reorganization items, net, (income) expense	$ (231)	$ (26)	$ (170)	$ —
Net (loss) income	$ (34,098)	$ 31,972	$ 52,649	$ (6,984)
Net (loss) earnings per share:				
Basic(2)	$ (0.42)	$ 0.39	$ 0.65	$ (0.09)
Diluted(2)	$ (0.42)	$ 0.39	$ 0.65	$ (0.09)

(1) Total expenses for the first quarter of 2020 includes a $289 million non-cash pre-tax asset impairment charge on properties in Utah and certain California locations. Total expenses for the fourth quarter of 2019 includes an impairment charge of $51 million for the Piceance gas properties in Colorado.

(2) In March 2019, we finalized settlement of claims from unsecured creditors, issuing approximately 2,770,000 shares. We retrospectively adjusted the weighted average shares in our earnings per share calculations for the 2,770,000 shares issued instead of the 7,080,000 shares that had been reserved. See Note 11 of our consolidated financial statements for further information.

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,		
	2020	2019	2018
	(in thousands)		
Property acquisition costs:			
Proved[(1)]	$ 11,597	$ 5,382	$ —
Unproved	—	—	—
Exploration costs	—	—	—
Development costs[(2)]	96,971	277,511	143,002
Total costs incurred	$ 108,568	$ 282,893	$ 143,002

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

(2) Included in development costs for the year ended December 31, 2020, 2019 and 2018 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $10.2 million, $65.7 million and $3.4 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,	
	2020	2019
	(in thousands)	
Proved properties	$ 1,181,865	$ 1,465,383
Unproved properties	311,195	313,903
Total proved and unproved properties	1,493,060	1,779,286
Less accumulated depreciation, depletion and amortization	(252,325)	(223,919)
Net capitalized costs	$ 1,240,735	$ 1,555,367

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,		
	2020	2019	2018
		(in thousands)	
Net revenues from production:			
Oil, natural gas and NGL sales	$ 378,663	$ 565,596	$ 552,874
Electricity sales	25,813	29,397	35,208
Other production-related revenue	1,431	2,258	2,908
Total net revenues from production[(1)]	405,907	597,251	590,990
Operating costs for production:			
Lease operating expenses	186,348	216,294	188,776
Electricity generation expenses	16,608	19,490	20,619
Transportation expenses	6,938	8,059	9,860
Production-related general and administrative expenses	1,766	2,735	1,876
Taxes, other than income taxes	34,987	40,254	33,117
Other production-related costs	1,380	2,073	2,140
Total operating costs for production	248,027	288,905	256,388
Other costs:			
Depreciation, depletion and amortization	135,361	101,816	81,927
Impairment of long-lived assets	289,085	51,081	—
Other operating expenses (income)	5,673	4,545	(2,747)
Total other costs	430,119	157,442	79,180
Pretax income (loss)	(272,239)	150,904	255,422
Income tax (benefit) expense	(83,467)	10,084	69,807
Results of operations	$ (188,772)	$ 140,820	$ 185,615

(1) Excludes cash received for scheduled derivative settlements of $142 million and $42 million for the years ended December 31, 2020 and 2019 and cash paid for scheduled derivative settlements of $38 million for the year ended December 31, 2018.

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.

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, 2020, 2019 and 2018 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, 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

	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

	Year Ended December 31, 2018			
	Oil MBbls	NGLs MBbls	Natural Gas MMcf	Total MBoe
Total proved reserves:				
Beginning of year	100,596	1,271	237,104	141,385
Extensions and discoveries	21,276	126	5,762	22,362
Revisions of previous estimates	80	211	(62,141)	(10,066)
Purchases of minerals in place	865	—	—	865
Sales of minerals in place	(7)	(250)	(10,287)	(1,972)
Production	(8,045)	(211)	(9,589)	(9,855)
End of year	114,765	1,147	160,849	142,720
Proved developed reserves:				
Beginning of year (Predecessor)	68,490	1,271	100,384	86,492
End of year	73,203	1,047	76,331	86,971
Proved undeveloped reserves:				
Beginning of year (Predecessor)	32,106	—	136,720	54,893
End of year	41,562	100	84,518	55,749

The tables above include changes in estimated quantities of natural gas reserves shown in Boe using the ratio of six Mcf to one barrel.

Proved reserves decreased by approximately 43,479 MBoe to approximately 94,943 MBoe for the year ended December 31, 2020, from 138,422 MBoe for the year ended December 31, 2019. The year ended December 31, 2020, includes 33,860 MBoe of negative revisions of previous estimates. Price-driven revisions were 30,909 MBoe, 91% of total revisions, and were due to the dramatic decline in commodity prices experienced in 2020. Performance revisions were a decrease of 2,951 MBoe, 9% of total revisions. Extensions and discoveries, exclusively in our California properties, added 733 MBoe 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 4,298 MBoe to approximately 138,422 MBoe for the year ended December 31, 2019, from 142,720 MBoe for the year ended December 31, 2018. Extensions and discoveries, principally in our California properties, contributed 13,321 MBoe 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 7,302 MBoe of negative revisions of previous estimates. Negative revisions due to price were 6,829 MBoe and this was caused by the current commodity price environment. Performance revisions included a decrease of 13,532 MBoe 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 revisions of 13,329 MMBoe primarily related to the improved base performance and redevelopment in our thermal Diatomite area.

Proved reserves increased by approximately 1,335 MBoe to approximately 142,720 MBoe for the year ended December 31, 2018, from 141,385 MBoe for the year ended December 31, 2017. Extensions and discoveries, principally in our California properties, most of which was thermal Diatomite, as well as in Utah, contributed 22,362 MBoe to the increase in proved reserves. The year ended December 31, 2018, includes approximately 10,066 MBoe of negative revisions of previous estimates 17,992 MBoe of negative performance related revisions resulting from 9,411 MBoe to remove proved undeveloped reserves due to a downward adjustment of our committed capital in the

Piceance basin and technical revisions of 8,581 MBoe due to a shift in the development strategy as laid out in our 5-year capital plan offset by 7,926 MBoe of positive revisions due to higher commodity prices).

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,		
	2020	2019	2018
	(in thousands, except for prices)		
Future cash inflows	$ 3,657,907	$ 7,788,647	$ 8,119,309
Future production costs	(2,091,021)	(3,623,688)	(3,357,149)
Future development costs	(830,028)	(1,106,333)	(884,055)
Future income tax expenses[1]	(1,646)	(587,487)	(757,470)
Future net cash flows	735,212	2,471,139	3,120,635
10% annual discount for estimated timing of cash flows	(219,033)	(1,005,002)	(1,359,089)
Standardized measure of discounted future net cash flows	$ 516,179	$ 1,466,137	$ 1,761,546
Representative prices:[2]			
Brent Oil (Bbl)	$ 41.77	$ 63.15	$ 71.54
Henry Hub Natural gas (MMBtu)	$ 2.03	$ 2.62	$ 3.10

(1) 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.

(2) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

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

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Standardized measure—beginning of year	$ 1,466,137	$ 1,761,546	$ 977,348
Net change in sales and transfer prices and production costs related to future production	(1,135,565)	(309,347)	818,705
Changes in estimated future development costs	198,009	(120,688)	35,313
Sales and transfers of oil, natural gas and NGLs produced during the period	(149,806)	(300,261)	(321,148)
Net change due to extensions, discoveries and improved recovery	11,621	180,825	363,450
Purchase of minerals in place	1,668	2,649	5,240
Sales of minerals in place	—	—	(5,593)
Net change due to revisions in quantity estimates	(329,680)	(124,110)	(175,947)
Previously estimated development costs incurred during the period	2,762	116,921	78,803
Accretion of discount	180,673	215,153	111,416
Changes in production rates and other	(69,293)	(5,939)	127,135
Net change in income taxes	339,653	49,388	(253,176)
Net increase (decrease)	(949,958)	(295,409)	784,198
Standardized measure—end of year	$ 516,179	$ 1,466,137	$ 1,761,546

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,		
	2020	2019	2018
Weighted-average realized prices:			
Oil without hedges (Bbl)	$ 39.56	$ 58.93	$ 64.76
Natural gas ($/Mcf)	$ 2.08	$ 2.66	$ 2.74
NGLs ($/Bbl)	$ 12.57	$ 17.02	$ 26.74
Production costs (per Boe):			
Lease operating expenses	$ 17.86	$ 20.42	$ 19.16

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, 2020. 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, 2020 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, 2020, 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, 2020.

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. There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2020 that materially affected, or were reasonably likely to materially affect, the Company's internal control 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 2021 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2020.

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 2021 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2020.

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 2021 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2020.

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 2021 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2020.

Item 14. Principal Accounting Fees and Services

The information required by this Item 14 is incorporated herein by reference to our definitive Proxy Statement, for the 2021 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2020.

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)
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)

Exhibit Number	Description
10.7†*	Amended and Restated Executive Employment Agreement by and between Berry Petroleum Company, LLC and Danielle Hunter, effective March 1, 2020
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)
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)

Exhibit Number	Description
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	Credit Agreement, dated July 31, 2017, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, Wells Fargo Bank, N.A., as administrative agent and issuing lender, and certain lenders (incorporated by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.26	Amendment No. 1, dated as of November 16, 2017, to the Credit Agreement, dated July 31, 2017, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, Wells Fargo Bank, N.A., as administrative agent and issuing lender, and certain lenders (incorporated by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.27	Amendment No. 2, dated as of March 8, 2018, to the Credit Agreement, dated July 31, 2017, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, Wells Fargo Bank, N.A., as administrative agent and issuing lender, and certain lenders (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.28	Amendment No. 3, dated November 14, 2018, to the Credit Agreement, dated July 31, 2017, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, Wells Fargo Bank, N.A., as administrative agent and issuing lender, and certain lenders (incorporated by reference to Exhibit 10.1 of Form 8-K filed November 15, 2018)
10.29	Amendment No. 4, dated December 17, 2019, to the Credit Agreement, dated July 31, 2017, by and among Berry Petroleum Company, LLC, as borrower, Berry Petroleum Corporation, as guarantor, Wells Fargo Bank, N.A., as administrative agent and issuing lender, and certain lenders (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 18, 2019)
10.30	Limited Waiver and Amendment No. 5 to Credit Agreement, dated as of June 23, 2020, among Berry Petroleum Company, LLC, as borrower, Berry Corporation (bry), as parent, Wells Fargo Bank, National Association, as administrative agent and the lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed June 26, 2020)
10.31	Amendment No. 6 to Credit Agreement, dated as of November 23, 2020, among Berry Petroleum Company, LLC, as borrower, Berry Corporation (bry), as parent, Wells Fargo Bank, National Association, as administrative agent and the lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed November 25, 2020)
10.32	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)
10.33	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)
21.1*	List of Subsidiaries of Berry Corporation (bry)
23.1*	Consent of KPMG LLP

Exhibit Number	Description
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, 2020 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:

*"Absolute TSR" m*eans absolute total stockholder return.

"AROs" means asset retirement obligations.

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

"*Adjusted Net Income (Loss)*" is a non-GAAP financial measure defined as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*EOR*" means enhanced oil recovery.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*ICE*" means Intercontinental Exchange.

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

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

"*IOR*" means improved oil recovery.

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

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

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

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

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

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

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

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

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

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

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

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

"*MMBtu*" means one million Btus.

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

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

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

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

"*MW*" means megawatt.

"*MWHs*" means megawatt hours.

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

"*NASDAQ*" means Nasdaq Global Select Market.

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

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

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

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

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

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

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

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

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

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

"*OTC*" means over-the-counter

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*QF*" means qualifying facility.

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

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

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

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

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

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

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

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

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

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

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

"SARs" is an abbreviation for stock appreciation rights.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*WTI*" means West Texas Intermediate.

SIGNATURES

Pursuant to the requirements of 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:	February 24, 2021	/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**
February 24, 2021	/s/ A. T. Smith A. T. "Trem" Smith	President and Chief Executive Officer, and Director (Principal Executive Officer)
February 24, 2021	/s/ Cary Baetz Cary Baetz	Executive Vice President and Chief Financial Officer, and Director (Principal Financial Officer)
February 24, 2021	/s/ M. S. Helm Michael S. Helm	Chief Accounting Officer (Principal Accounting Officer)
February 24, 2021	/s/ Brent S. Buckley Brent S. Buckley	Director
February 24, 2021	/s/ Renée Hornbaker Renée Hornbaker	Director
February 24, 2021	/s/ Anne L. Mariucci Anne L. Mariucci	Director
February 24, 2021	/s/ Donald L. Paul Donald L. Paul	Director
February 24, 2021	/s/ E. J. Voiland Eugene J. Voiland	Director

DIRECTORS

A.T. (TREM) SMITH
Board Chair, Chief Executive Officer & President
Berry Corporation (bry)

CARY BAETZ
Executive Vice President & Chief Financial Officer
Berry Corporation (bry)

BRENT BUCKLEY (1) (2)
Independent Director
Managing Director with Benefit Street Partners

RENÉE HORNBAKER (1C)
Independent Director
Chief Executive Officer of Storey & Gates LLC

ANNE MARIUCCI (1) (2C) (3)
Lead Independent Director
Former President of Del Webb Corporation

DONALD PAUL (2) (3C)
Independent Director
Executive Director of the Energy Institute, the William M. Keck Chair of Energy Resources & Research, Professor of Engineering at the University of Southern California

EUGENE (GENE) VOILAND (1) (3)
Independent Director
Former President & Chief Executive Officer of Aera Energy LLC

(C) Committee Chair
(1) Audit Committee
(2) Compensation Committee
(3) Nominating & Corporate Governance Committee

EXECUTIVE OFFICERS

A.T. (TREM) SMITH
Board Chair, Chief Executive Officer & President

CARY BAETZ
Executive Vice President & Chief Financial Officer, Director

FERNANDO ARAUJO
Executive Vice President & Chief Operating Officer

DANIELLE HUNTER
Executive Vice President, General Counsel & Corporate Secretary

KURT NEHER
Executive Vice President, Business Development

INVESTOR RELATIONS
Todd Crabtree
Berry Corporation (bry)
16000 N. Dallas Pkwy, Ste 500
Dallas, TX 75248
(661) 616-3811
ir@bry.com

TRANSFER AGENT/REGISTRAR
American Stock Transfer & Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219

Shareholder Services
(718) 921-8214
astfinancial.com

SECURITIES
Berry Common Stock is traded on Nasdaq under the symbol BRY.

ANNUAL REPORT ON FORM 10-K FOR 2020
Our Form 10-K is included in this document in its entirety as filed with the SEC. Upon request to Investor Relations, we will deliver free of charge a copy of our Form 10-K.

TOTAL SHAREHOLDER RETURN PERFORMANCE GRAPH
Our Form 10-K includes a performance graph comparing the cumulative total return to shareholders on our common stock relative to the cumulative total returns of the S&P Smallcap 600, the Dow Jones U.S. Exploration and Production indexes and the Vanguard Energy ETF (with reinvestment of all dividends).

DIVIDEND PAYMENT DATES - 2021
Quarterly Dividends on common stock are paid, following declaration by the Board of Directors, on approximately the 15th day of January, April, July and October.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
KPMG LLP, Los Angeles, California
kpmg.com

CAUTIONARY NOTE ON FORWARD-LOOKING STATEMENTS
This report includes forward-looking statements involving risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects, including our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, maintenance capital requirements, expected production and costs, reserves, hedging activities, capital expenditures, return of capital, improvement of recovery factors and other guidance. Factors (but not necessarily all the factors) that could cause results to differ from anticipated results include: oil and gas price volatility; inability to generate or to obtain financing to fund capital expenditures, meet working capital requirements and fund planned investments; price and availability of natural gas; ability to hedge price risk; availability and the timing of required permits and approvals and our inability to meet existing or new conditions imposed on those permits and approvals; ability to meet our planned drilling schedule and drilling risks; the impact of current laws and regulations, and of pending or future legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products; proved reserves estimation uncertainties; ability to replace our reserves; lower–than–expected production or reserves from development projects or higher–than–expected decline rates; economic viability of drilled wells; changes in tax laws; competition; ability to make successful acquisitions; electricity price fluctuations and steam costs; and other material risks that appear in "Item 1A - Risk Factors" of our Form 10-K and other periodic reports filed with the SEC.

THE CORE VALUES THAT DEFINE OUR COMPANY CULTURE:

LEADERSHIP

—

ENTREPRENEURSHIP

—

ACCOUNTABILITY

—

OWNERSHIP

—

COMMUNICATION

bry®
BERRY CORPORATION

INVESTOR RELATIONS Berry Corporation (bry) 16000 N. Dallas Pkwy, Ste 500 Dallas, Texas 75248
ir@bry.com **bry.com**