Founded on Value. Focused on Growth.

2018 ANNUAL REPORT

2018 Adjusted EBITDA* of

$258M

2018 Cash Flows from Operations of

$230M

(excluding $127 million for hedge early termination)

California PV-10* of **$2 billion out of $2.2 billion total**

Replaced 275% reserves* in California and 114% of total company reserves

Letter to shareholders

Value Focused

2018 was monumental for Berry. By executing our simple and clear business model, Berry was and continues to be wholly focused on value creation for its shareholders. Our goal is always to generate growth while operating within our levered free cash flow. We manage to value and not just to volume growth and we did this in 2018 with excellence, realizing operational efficiencies, production growth and incident prevention improvements.

Most notably on July 26, just a short 16 months after emerging from bankruptcy, we began trading on the Nasdaq, reinforcing our strong position in the industry and value in the market.

California Focus

Last year was all about California, where we produced 100% oil, spent most of our capital, and realized all of our production growth as well as the preponderance of our operating income. As a result, we added more than $1 billion to our PV-10* valuation and accomplished a 275% reserve* replacement ratio. Our operations are focused in California, too. Approximately 70% of our total company production came from the world-class super basin, the San Joaquin Basin, and approximately 94% of the production is in Kern County alone. Just three fields on the west side of the Basin (Belridge, McKittrick and Midway Sunset) made up 80% of our production in California and 59% of our total production. We remain focused on thermal recovery of heavy oil in shallow, conventional reservoirs—perfect for the refineries in California. Finally, we drilled 224 wells in California in 2018, resulting in a 15% production increase.

Further, our bolt-on strategy, the addition of low-risk acreage near our existing production and infrastructure, was effective. We now have access to 879 new acres through bolt-ons completed in 2018, increasing our acreage position in the Midway Sunset Field by about 20%.

Future Focus

Looking ahead, our focus isn't changing in 2019. We currently have, and expect to continue to have, four rigs running, all in California.

We will direct even more capital to California than we did in 2018 where we expect a mid- to high-teen production exit growth rate and continued significant reserve growth. In 2019, we forecast approximately 94% of our capital including 98% of our development capital to be spent in California and plan to drill approximately 400 wells.

We are in a great position for continued improvement to maximize the value of our existing fields while continuously looking for growth through bolt-ons and strategic acquisitions. We have several bolt-on opportunities under negotiations, which, if fully executed, could grow our acreage position in Midway Sunset by more than 50%.

Berry's future looks bright. Our technical assessment of our current resource and original oil in place indicates that a simple 1% increase in recovery factor could result in the addition of more than 20 million barrels of oil in California.

Berry First Focus

We are dedicated to our Berry First approach—to be the leader in this industry. With the commitment of all 325+ employees, we will continue to execute our plan with excellence, growing our company and, as always, creating value for our shareholders.

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

*For definitions and GAAP reconciliations, see Form 10-K "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" and "Items 1 and 2. Business and Properties—Our Reserves and Production Information". Reserves replacement ratio is calculated by dividing the sum of proved reserve extensions and discoveries, revisions of previous estimates, improved recovery and purchases and sales of minerals in place for the year by current year production. There is no guarantee that historical sources of reserves additions will continue.

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, 2018

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 PETROLEUM CORPORATION
(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	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.001 per share	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐
Emerging Growth Company ☒

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

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

As of June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter, the registrant's equity was not listed on any domestic exchange or over-the-counter market. The registrant's common stock began trading on the Nasdaq Global Select Market ("NASDAQ") on July 26, 2018.

Shares of common stock outstanding as of February 28, 2019 82,061,650

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held May 14, 2019) will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2018 and is incorporated by reference in Part III to the extent described herein.

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

Part I

Items 1 and 2. Business and Properties

When we use the terms "we," "us," "our," the "Company," or similar words in this report, unless the context otherwise requires, on or prior to the Effective Date (as defined below in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Lawsuits, Claims, Commitments, and Contingencies"), we are referring to Berry LLC, our predecessor company, and following the Effective Date, we are referring to Berry Corp. and its subsidiary, Berry LLC, together, the successor company, as applicable.

Our Company

We are a western United States independent upstream energy company with a focus on the conventional, long-lived oil reserves in the San Joaquin basin of California. Our long-lived, high-margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive levered free cash flow through commodity price cycles. Successful execution of our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient production growth as well as the ability to continue returning capital to our stockholders.

We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and, to a lesser extent, our Rockies assets including low-cost, oil-rich reservoirs in the Uinta basin of Utah and low geologic risk natural gas resource plays in the Piceance basin in Colorado. In the aggregate, the Company's assets are characterized by:

- high oil content, which has grown to over 85% of our production;
- favorable Brent-influenced crude oil pricing dynamics;
- long-lived, conventional reserves with low and predictable production decline rates;
- stable development and production cost structures;
- an extensive inventory of low-risk identified development drilling opportunities with attractive full-cycle economics; and
- potential in-basin organic and strategic opportunities to expand our existing inventory with new locations of substantially similar geology and economics.

California is and has been one of the most productive oil and natural gas regions in the world. Our asset base is concentrated in the oil-rich San Joaquin basin in California, which has more than 100 years of production history, substantial remaining oil in place, and is considered a super basin. As a result of the substantial data produced over the basin's long history, its geological and reservoir characteristics are well understood, leading to predictable, repeatable, low-risk development opportunities.

In California, we focus on conventional, shallow reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. Our decades-old proven completion techniques in these reservoirs include cyclic and continuous steam injection and low-volume hydraulic stimulation. For example, we estimate the cost to drill and complete our PUD wells in California will be less than $375,000 per well. In contrast, we estimate the cost to drill and complete our PUD wells in our Rockies operations will average $1.3 million per well.

As noted, we own additional assets in the Uinta basin in Utah, a mature, light-oil-prone play with significant undeveloped resources where we have high operational control and additional behind pipe potential, as well as in the Piceance basin in Colorado, a prolific low geologic risk natural gas play where we produce from a conventional, tight sandstone reservoir using proven slick water stimulation techniques to increase recoveries. On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

As of December 31, 2018, we had estimated total proved reserves of 142,720 MBoe. For the year ended December 31, 2018, we had average production of approximately 27.0 MBoe/d, of which approximately 82% was oil. For the three months ended December 31, 2018, we had average production of approximately 28.0 MBoe/d, of which approximately 85% was oil. In California, our average production for the year and the quarter ended December 31, 2018 was 19.7 MBoe/d and 21.7 MBoe/d, respectively, of which approximately 100% was oil.

The Berry Advantage

We believe that our combination of low production decline rates, high-margin Brent-influenced oil-weighted production, attractive development opportunities and a stable cost environment differentiates us from our competitors and allows us to break even on a cash flow basis and maintain production at relatively low commodity prices. Our advantages give us an ability to generate top-tier corporate level returns, positive Levered Free Cash Flow and capital-efficient growth through commodity price cycles. “Levered Free Cash Flow” is a non-GAAP financial measure defined as Adjusted EBITDA less interest expense, dividends and capital expenditures.

Our Low Declining Production Base

Our California reserves are predominantly long-lived and characterized by relatively low production decline rates and development costs, affording us significant capital flexibility and an ability to hedge efficiently material quantities of future expected production. For example, our PDP reserves have an estimated annual decline rate of approximately 19% to 11% in the years between 2019 and 2024 based on total PDP Boe reserves as of December 31, 2018 as reflected in our SEC reserves report, which is attached as Exhibit 99.1. Our SEC reserves report is based on the estimated individual well production profiles used to determine our PDP reserves. Based on the assumptions underlying our PUD estimates, we estimate that we will require slightly more than $10 per Boe in annual capital expenditures to keep production volumes consistent each year over the next three years. In addition to our low and stable cash operating costs, which were approximately $26 per Boe in 2018, we can operate and maintain production at relatively low commodity price levels. Considering our typical realized prices, we believe our operations break even when crude prices are at or above $45 Brent.

Our High-Margin Brent-Influenced Oil-Weighted Production

Our highly oil-weighted production combined with a Brent-influenced California pricing dynamic and stable cost structure has resulted, and is expected to continue to result, in strong operating margins at current commodity prices. As of December 31, 2018, our California PUD reserves were 100% oil.

Our Stable California Operating and Development Cost Environment

The operating and development cost structures of our conventional California asset base are inherently stable and predictable. Our California focus has insulated us from the cost inflation pressures experienced by our peers who operate primarily in unconventional plays. This is the result of our established infrastructure, low-intensity service requirements and lack of dependence on inventory-constrained and often highly specialized equipment. In addition, the majority of our California assets are located in the fields of the San Joaquin basin and are characterized by heavy oil found in shallow reservoirs. The costs to develop these reservoirs are lower when compared to the water flood fields of the Los Angeles and Ventura basins.

Our Reserves and Assets

As of December 31, 2018, we had estimated total proved reserves of 142,720 MBoe. For the year ended December 31, 2018, we had average production of approximately 27.0 MBoe/d, of which approximately 82% was oil. For the three months ended December 31, 2018, we had average production of approximately 28.0 MBoe/d, of which approximately 85% was oil. In California, our average production for the year and the quarter ended December 31, 2018 was 19.7 MBoe/d and 21.7 MBoe/d, respectively, of which approximately 100% was oil.

The majority of our reserves are composed of heavy crude oil in shallow, long-lived reservoirs. As of December 31, 2018, approximately three quarters of our proved reserves and approximately 94% of the PV-10 value of our proved reserves are derived from our assets in California. We also operate 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. On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

As of December 31, 2018, the standardized measure of discounted future net cash flows of our proved reserves and the PV-10 of our proved reserves were approximately $1.8 billion and $2.2 billion, 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 "—Our Reserves and Production Information—PV-10".

The tables below summarize our proved reserves and PV-10 by category as of December 31, 2018:

	Proved Reserves as of December 31, 2018[1]							
	Oil (MMBbl)	Natural Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% of Proved	% Proved Developed	Capex[2] ($MM)	PV-10[3] ($MM)
PDP	62	76	1	76	53%	87%	$ 35	$ 1,263
PDNP	11	—	—	11	8%	13%	24	248
PUD	42	85	—	56	39%	—%	683	641
Total	115	161	1	143	100%	100%	$ 742	$ 2,152
California	106	—	—	106	N/A	N/A	$ 603	$ 2,027

(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 $71.54 per Bbl Intercontinental Exchange ("ICE") Brent oil ("Brent") for oil and natural gas liquids ("NGLs") and $3.10 per MMBtu New York Mercantile Exchange ("NYMEX") Henry Hub ("Henry Hub") for natural gas at December 31, 2018. The volume-weighted average prices over the lives of the properties were estimated at $66.49 per Bbl of oil and condensate, $32.87 per Bbl of NGLs and $2.806 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) Represents undiscounted future capital expenditures estimated as of December 31, 2018.

(3) 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 table below summarizes our average net daily production by basin for the year ended December 31, 2018:

	Average Net Daily Production[(1)] for the Year Ended December 31, 2018	
	(MBoe/d)	Oil (%)
California	19.7	100%
Rockies	7.3	32%
Total	27.0	82%

(1) Production represents volumes sold during the period.

Our Development Inventory

We have an extensive inventory of low-risk, high-return development opportunities. As of December 31, 2018, we identified 3,314 gross drilling locations company-wide that we anticipate drilling over the next 5 to 10 years, which we refer to as our “Tier 1” locations, and 3,716 additional gross drilling locations that are currently under review. For a discussion of how we identify drilling locations, please see “—Our Reserves and Production Information—Determination of Identified Drilling Locations.”

We operate approximately 98% of our producing wells. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. The combined net acreage covered by leases expiring in the next three years represented approximately 5% of our total net acreage at December 31, 2018. Our high degree of operational control, together with the large portion of our acreage that is held by production, 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 operations as of December 31, 2018:

	Acreage		Net Acreage Held By Production(%)	Producing Wells, Gross[(1)(2)]	Average Working Interest (%)[(2)(3)]	Net Revenue Interest (%)[(2)(4)]	Identified Drilling Locations[(5)]	
	Gross	Net					Gross	Net
California	11,268	8,333	99%	2,698	99%	93%	4,923	4,915
Rockies	134,470	100,126	73%	1,105	94%	75%	2,107	1,747
Total	145,738	108,459	75%	3,803	98%	89%	7,030	6,662

(1) Includes 540 steamflood and waterflood injection wells in California.
(2) Excludes 91 wells in the Piceance basin each with a 5% working interest.
(3) Represents our weighted-average working interest in our active wells.
(4) Represents our weighted-average net revenue interest for the year ended December 31, 2018.
(5) Our total identified drilling locations include approximately 1,071 gross (1,058 net) locations associated with PUDs as of December 31, 2018, including 88 gross (88 net) steamflood injection wells. Please see “—Our Reserves and Production Information—Determination of Identified Drilling Locations” for more information regarding the process and criteria through which we identified our drilling locations.

Our Competitive Strengths

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

- ***Stable, low-decline, predictable and oil-weighted conventional asset base***. The majority of our interests are in properties that have produced 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 are characterized by long-lived reserves with low production decline rates, a stable cost structure and low-risk developmental drilling opportunities with predictable production profiles. The nature of our assets provides us with a high degree of capital flexibility through commodity cycles.

- ***Substantial inventory of low-cost, low-risk and high-return development opportunities***. We expect our locations to generate highly attractive rates of return. For example, our PUD reserves in California are projected to average single-well rates of return of approximately 39% based on the assumptions used in preparing our SEC reserves report as of December 31, 2018.

- ***Brent-influenced pricing advantage***. California oil prices are Brent-influenced as California refiners import more than 50% of the state's demand from foreign sources. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs 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, will allow us to continue to realize strong cash margins in California.

- ***Substantial capital flexibility derived from a high degree of operational control and stable cost environment***. We operate over 95% of our producing wells and expect to operate a similar percentage of our identified gross drilling locations. In addition, approximately 75% of our acreage is held by production, including 99% of our acreage in California. Our high degree of operational control over our properties, together with the large portion of our acreage that is held by production, gives us flexibility in executing our development program, including the timing, amount and allocation of our capital expenditures, technological enhancements and marketing of production. We expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to return capital to stockholders and fund maintenance operations and growth among other things. Also, unlike our peers, who operate primarily in unconventional plays, our assets generally do not necessitate inventory-constrained and highly specialized equipment, which provides us relative insulation from 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.

- ***Simple capital structure and conservative balance sheet leverage with ample liquidity and minimal contractual obligations***. In connection with our 2018 IPO, we converted all of our Series A Preferred Stock (the "Series A Preferred Stock") into common stock (the "Series A Preferred Stock Conversion"). Earlier in 2018, we closed a private offering 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. As of December 31, 2018, we had $462 million of available liquidity, defined as cash on hand plus availability under the $1.5 billion reserves-based lending facility we entered into on July 31, 2017 (as amended, the "RBL Facility"). 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 grow and increase stockholder value.

- ***Ability and intention to return capital to stockholders consistently through the commodity price cycle.*** We generated positive Levered Free Cash Flow in 2018 when Brent oil prices ranged from a mid-year high of $86.29 to a low of $50.47 toward the end of the year. In California, we believe our operations break even when Brent crude prices are approximately $47 per barrel, meaning we expect to have positive Levered Free Cash Flow at that level. We have paid a dividend on our common stock since our first quarter as a public company and plan to continue paying a meaningful quarterly dividend.

- ***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 growing Levered Free Cash Flows as well as 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 new to our properties in order to generate a sustained cost advantage.

Our Business Strategy

The principal elements of our business strategy include the following:

- ***Grow production and reserves in a capital efficient manner while producing positive internally generated Levered Free Cash Flow***. We intend to allocate capital in a disciplined manner to projects that will produce predictable and attractive rates of return. We plan to direct capital to our oil-rich and low-risk development opportunities while focusing on driving cost 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.

- ***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 explore innovative EOR techniques to unlock additional value and have allocated capital towards next generation technologies. For example, in our South Belridge Hill non-thermal and Midway-Sunset thermal Diatomite properties, we employ both hydraulic stimulation and advanced thermal techniques, and in our Piceance properties, we use advanced proppantless slick water well stimulation techniques. 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.

- ***Proactively and collaboratively engage in matters related to regulation, safety, environmental and community relations***. We are committed to proactive engagement with regulatory agencies 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 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 facilitate our permitting process. We have found constructive dialogue with regulatory agencies can help avert compliance and permitting issues. By working with the legislators and regulators on the front end of the regulatory process, our goal is to minimize the impact of new regulations and legislation and to mitigate the risk of permitting delays.

- ***Return excess free cash flow to stockholders***. Our objective is to implement a disciplined and returns-focused approach to capital allocation in order to generate excess free cash flow. We intend to return portions of that excess free cash flow to stockholders on a quarterly basis. If commodity prices increase for a sustained period of time, we would consider repaying debt obligations or returning additional capital to stockholders. For a discussion of our dividend policy, please see "Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Dividend Policy."

- ***Maintain balance sheet strength and flexibility through commodity price cycles***. We intend to fund our capital program while producing positive internally generated Levered Free Cash Flow. Over time, we expect to de-lever through organic growth and 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 1.5x and 2.0x.

- ***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 portion of our anticipated crude oil production realizations into 2020. We will review our hedging program continuously as conditions change.

Our Capital Budget

Immediately following Berry LLC's emergence from bankruptcy and separation from Linn Energy, LLC ("Linn Energy") and LinnCo, LLC ("LinnCo" and, together with Linn Energy, the "Linn Entities") in 2017, we increased our pace of development and have continued to do so throughout 2018 and into 2019. For the years ended December 31, 2018 and 2017, our capital expenditures were approximately $148 million and $73 million, respectively, on an accrual basis excluding acquisitions. Our 2019 anticipated capital expenditure budget is approximately $195 to $225 million, which represents an increase of approximately 42% over 2018 capital expenditures. Capital expenditures increased 103% from 2017 to 2018. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2019 capital development programs while producing positive Levered Free Cash Flow. Our 2019 capital program is focused on growing our oil production in California. We anticipate oil production will be approximately 86% of total production in 2019, compared to 82% in 2018. This change in product mix was also a factor in the divestiture of our non-core East Texas gas properties in late 2018. During 2019, we expect to:

- employ four drilling rigs in California throughout the year; and

- drill approximately 370 to 420 gross development wells, all of which we expect will be in California for oil production.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these 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 availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, 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. For additional information about the 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—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Capital Expenditures and Capital Budget".

Our Areas of Operation

Our predominant operating area is in California, and we also have operations in the Rockies. On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

California

According to the U.S. Geological Survey as of 2012, the San Joaquin basin in California contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. We have operations in two of the three fields —Midway-Sunset and South Belridge. California is and has been one of the most productive oil regions in the world, and is currently ranked as the third largest state in reserves and sixth largest state in production in the U.S.

In California, we actively operate and develop properties located in the Midway-Sunset, South Belridge, McKittrick and Poso Creek fields in the San Joaquin basin in Kern County as well as the Placerita Field in the Ventura basin in Los Angeles County. We currently hold 8,333 net acres in these basins with a 99% average working interest. The producing areas in our Southeast San Joaquin operations include: (i) our South Midway-Sunset, properties, which are long-life, low-decline, strong-margin thermal oil properties with additional development opportunities; (ii) our Poso Creek property, which is an active mature shallow, heavy oil asset that we continue to develop across the property; and (iii) our Placerita property, which is a mature shallow, heavy oil asset with additional recompletion opportunities. The producing areas in our Northwest San Joaquin operations include: (i) our McKittrick Field property, which is a newer steamflood development with potential for infill and extension drilling; (ii) 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; (iii) our thermal North Midway-Sunset Diatomite properties, where we utilize innovative EOR techniques to unlock significant value and maximize recoveries; and (iv) our North Midway-Sunset sandstone properties, where we use cyclic and continuous steam injection to develop these known reservoirs. Our California proved reserves represented approximately 74% of our total proved reserves at December 31, 2018 and accounted for 19.7 MBoe/d or 73% of our average daily production for the year ended December 31, 2018 and 21.7 MBoe/d or 78% of our average daily production for the three months ended December 31, 2018.

Along with these upstream operations, we have extensive 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 assist in this operation, we own and operate five natural gas cogeneration plants that produce steam. These plants supply approximately 24% of our steam needs and approximately 63% of our field electricity needs in California at a discount to electricity market prices. To further 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 and operate 79 conventional steam generators.

In addition, we own gathering, treatment, water recycling and softening facilities, and 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 80% of our California oil production is sold through pipeline connections, and we have contracts in place with third-party purchasers of our crude.

According to the Division of Oil, Gas, and Geothermal Resources of the California Department of Conservation ("DOGGR"), approximately 76% of California's daily oil production of 477 MBbl/d for 2017 was produced in the San Joaquin basin. 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. We began operations in California in 1909. In the 1960s, introduction of thermal techniques resulted in substantial new additions to reserves in heavy oil fields. The San Joaquin basin contains multiple stacked benches that have allowed continuing discoveries of stratigraphic, structural and non-structural traps. Most oil accumulations discovered in the San Joaquin basin occur in the Eocene age through Pleistocene age sedimentary sections. Organic rich shales from the Monterey, Kreyenhagen and Tumey formations form the source rocks that generate the oil for these accumulations. We believe there are extensive existing field redevelopment opportunities in our areas of operation within the San Joaquin basin. We believe that our California focus and strong balance sheet will allow us to take advantage of these opportunities.

Rockies

<u>Uinta basin</u>

Our Uinta basin operations in the Brundage Canyon, Ashley Forest and Lake Canyon areas 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 has significant upside for additional vertical and or horizontal development and recompletions. Our Uinta basin proved reserves represented approximately 13% of our total proved reserves at December 31, 2018 and accounted for 4.9 MBoe/d or 18% of our average daily production for the year ended December 31, 2018.

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 95% of the gas gathered at these facilities is produced from wells that we operate. Current throughput at the processing plant is 16-18 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 production more than doubled from 36 MBbl/d in 2003 to 93 MBbl/d in 2017. Approximately 82% of Utah's production in 2017 came from the Uinta basin in Duchesne and Uintah counties.

Piceance basin

Our primary operating areas in the Piceance basin are Garden Gulch and North Parachute 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. Our Piceance basin proved reserves represented approximately 13% of our total proved reserves at December 31, 2018 and accounted for 1.7 MBoe/d or 6% of our average daily production for the year ended December 31, 2018.

The Piceance basin is located in northwestern Colorado and is a low geologic risk gas play with trillions of cubic feet of natural gas in place. 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.

Methods of Recovery

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 a high working interest and operating control in our properties.

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

					Gross Drilling Locations(1)		
State	**Project Type**	**Well Type**	**Completion Type**	**Recovery Mechanism**	**Tier 1**	**Additional**	**Total**
California	Hill Diatomite (non-thermal)	Vertical	Low intensity pin point	Pressure depletion augmented with water injection	272	585	857
California	Thermal Diatomite	Vertical	Short interval perforations	Cyclic steam injection	787	979	1,766
California	Thermal Sandstones	Vertical / Horizontal	Perforation/Slotted liner/gravel pack	Continuous and cyclic steam injection	1,811	489	2,300
Utah	Uinta	Vertical / Horizontal	Low intensity hydraulic stimulation	Pressure depletion	444	793	1,237
Colorado	Piceance	Vertical	Proppantless slick water stimulation	Pressure depletion	—	870	870
Total					**3,314**	**3,716**	**7,030**

(1) We had 1,071 gross (1,058 net) locations associated with PUDs as of December 31, 2018 including 88 gross (88 net) steamflood injection wells. Of those 1,071 gross PUD locations, 977 are associated with projects in California, 55 are associated with the Piceance basin, and 39 are associated with the Uinta basin. Please see "—Our Reserves and Production Information—Determination of Identified Drilling Locations" for more information regarding the process and criteria through which we identified our drilling locations. During the year ended December 31, 2018, we drilled 121 gross (121 net) wells that were associated with PUDs at December 31, 2017, including 27 gross (27 net) steamflood injection wells.

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, Poso Creek, McKittrick, South Belridge 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 steam injection projects are generally shallower in depth (300 to 1,200 ft) than our other programs and the wells are relatively inexpensive to drill and complete at approximately $350,000 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 Business and Industry—We are dependent on our cogeneration facilities to produce steam for our operations. Viable 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 79 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 147,000 gallons of water per well for our Hill hydraulic stimulations compared to a median of nearly 4 million gallons for horizontal, unconventional shale wells hydraulically stimulated in the United States in 2014. Similarly, we expect to use only about 325,000 pounds of sand per Hill well compared to a nationwide average of over 4 million pounds of sand per well in 2015. We use low-volume hydraulic reservoir stimulation in the San Joaquin basin to stimulate our non-thermal Diatomite reservoir at the Hill property. We applied this technique in 2018 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 and electricity.

Crude Oil. Approximately 80% 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 50% of the state's demand from foreign sources. This dynamic has led to periods 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, 2018, 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.

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, 2018, 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.

Electricity

Generation. Our cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. The total 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 costs in our heavy oil operations and to secure operating control of our steam generation.

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 2019 and 2022.

Electricity and steam produced from our Pan Fee and 21Z cogeneration facilities are used solely for field operations with one facility being run at a time and the other acting as 100% backup for the power produced on the lease.

For the year ended December 31, 2018, we sold approximately 1,800 megawatt-hours ("MWhs") per day and consumed approximately 300 MWhs per day of electricity generated by our five cogeneration facilities. In addition, the five cogeneration facilities produced an average of approximately 35,000 barrels of steam per day.

Principal Customers

For the year ended December 31, 2018, sales to Andeavor, Phillips 66 and Kern Oil & Refining accounted for approximately 35%, 28%, and 13% respectively, of our sales. At December 31, 2018, trade accounts receivable from three customers represented approximately 26%, 22% and 10% 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 Business and Industry".

Our Reserves and Production Information

Reserve Data

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2018. 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, 2018[1]		
	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Proved developed reserves:			
Oil (MMBbl)	66	7	73
Natural Gas (Bcf)	—	76	76
NGLs (MMBbl)	—	1	1
Total (MMBoe)[2][3]	66	21	87
Proved undeveloped reserves:			
Oil (MMBbl)	40	2	42
Natural Gas (Bcf)	—	85	85
NGLs (MMBbl)	—	—	—
Total (MMBoe)[3]	40	16	56
Total proved reserves:			
Oil (MMBbl)	106	9	115
Natural Gas (Bcf)	—	161	161
NGLs (MMBbl)	—	1	1
Total (MMBoe)[3]	106	37	143
PV-10 ($MM)[4]	$ 2,027	$ 125	$ 2,152

(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 $71.54 per Bbl ICE (Brent) for oil and NGLs and $3.10 per MMBtu NYMEX (Henry Hub) for natural gas at December 31, 2018. The volume-weighted average prices over the lives of the properties were $66.49 per Bbl of oil and condensate, $32.87 per Bbl of NGLs and $2.806 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 Business and Industry—Oil, natural gas and NGL prices are volatile and directly affect our results."

(2) Approximately 9% of proved developed oil reserves, 1% of proved developed NGL reserves, 0% of proved developed natural gas reserves and 8% of total proved developed reserves 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, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

(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. Calculation of PV-10 does not give effect to derivatives transactions. 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, 2018:

	At December 31, 2018
	(in millions)
California PV-10	$ 2,027
Rockies PV-10	125
Total Company PV-10	2,152
Less: present value of future income taxes discounted at 10%	(390)
Standardized measure of discounted future net cash flows	$ 1,762

Proved Reserves Additions

The total changes to our proved reserves from December 31, 2017 to December 31, 2018 were as follows:

	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	East Texas basin[(1)]	Total
		(in MMBoe)		
Beginning balance as of December 31, 2017	93	46	2	141
Extensions and discoveries	19	3	—	22
Revisions of previous estimates	—	(10)	—	(10)
Purchases of minerals in place	1	—	—	1
Sales of minerals in place	—	—	(2)	(2)
Current year production	(7)	(3)	—	(10)
Ending balance as of December 31, 2018	106	37	—	143

Note: 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, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

(1) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

Extensions and Discoveries. During 2018 we added 22 MMBoe of proved reserves from extensions and discoveries principally in our California properties, most of which was thermal Diatomite, as well as in Utah.

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 lives and renders more projects economic. Conversely, when prices drop, we experience the opposite effects. In 2018, our total net positive price revision was 8 MMBoe, which was primarily the result of higher prices in the commodity price environment in 2018 compared to 2017.

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 2018, our net negative performance-related revision of 18 MMBoe resulted from negative revisions of 9 MMBoe to remove proved undeveloped reserves due to a downward adjustment of our committed capital in the Piceance basin and technical revisions of 9 MMBoe due to a shift in the development strategy as laid out in our 5-year capital plan, predominantly in the thermal Diatomite area.

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 Additions

The total changes to our proved undeveloped reserves from December 31, 2017 to December 31, 2018 were as follows:

	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	East Texas basin	Total
		(in MMBoe)		
Beginning balance as of December 31, 2017	32	23	—	55
Extensions and discoveries	17	2	—	19
Revisions of previous estimates	(1)	(10)	—	(11)
Reclassifications to proved developed	(9)	—	—	(9)
Purchases of minerals in place	1	—	—	1
Ending balance as of December 31, 2018	40	15	—	55

Note: 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, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

Extensions and Discoveries. During 2018 we added 19 MMBoe of proved undeveloped reserves from extensions and discoveries due to drilling unproven locations in Midway Sunset and Uinta. We also added proven undeveloped reserves for our thermal Diatomite, Buena Fe and Uinta locations.

Revisions of previous estimates.

Revisions related to price - In 2018, our net positive price revision on proven undeveloped reserves was 1 MMBoe, which was primarily the result of higher prices due to the current commodity price environment.

Revisions related to performance - In 2018, our net negative performance-related revision on proven undeveloped reserves was 12 MMBoe, which resulted primarily from the removal of 9 MMBoe in proved undeveloped reserves due to a downward adjustment of our committed capital in the Piceance basin and technical revisions of 2 MMBoe due to a shift in the development strategy as laid out in our 5-year capital plan, predominantly in the thermal Diatomite area.

Reclassifications to proved developed. Through the 2018 drilling program, we transferred 9 MMBoe of proved undeveloped reserves to the proved developed category in California. As a result, we converted 16% of our beginning-of-the year inventory of proved undeveloped reserves, spending approximately $36 million of capital. The conversion rate reflected a gradual increase in capital spend from the lower pace of development in the prior year. At average Brent oil prices between $65 to $75 per barrel and average Henry Hub gas prices of at least $3.00 per mcf, we expect to have sufficient future capital to develop our proved undeveloped reserves at December 31, 2018 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 realized 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 Kurt Neher, who has a Masters in Geology from the University of South Carolina and a Bachelors in Geology from Carleton College, and more than 31 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 was Gregory K. Graves, P.E. Mr. Graves is a Registered Professional Engineer in the State of Texas (License No. 70734), is a member of both the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers and has in excess of 33 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Graves graduated from the University of Texas at Austin in 1984 with a Bachelor of Science degree in Petroleum Engineering.

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 Business 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, 2018, we have approximately 1,071 gross (1,058 net) drilling locations attributable to our proved undeveloped reserves. 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 will be 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 5,959 gross (5,604 net) drilling locations that are not associated with our proved undeveloped reserves but 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.

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 profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, 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 Business and Industry—We may not drill our identified sites at the times we scheduled or at all."

The table below sets forth our PUD locations and total identified drilling locations as of December 31, 2018.

	PUD Locations (Gross)		Total Identified Drilling Locations (Gross)(1)	
	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells
California	889	88	4,141	782
Rockies	94	—	2,107	—
Total Identified Drilling Locations	983	88	6,248	782

(1) Includes 3,314 Tier 1 gross drilling locations company-wide that we anticipate drilling over the next 5 to 10 years and 3,716 additional gross drilling locations that are currently under review.

Production and Operating Data

The following table sets forth information regarding production, realized and benchmark prices, and production costs for the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Production Data[3]:				
Oil (MBbl/d)	22.0	20.6	19.5	23.1
Natural gas (MMcf/d)	26.3	49.4	71.7	78.1
NGLs (MBbl/d)	0.6	2.0	5.2	3.6
Average daily combined production (MBoe/d)[1]	27.0	30.9	36.7	39.7
Oil (MBbl)	8,045	6,318	1,153	8,463
Natural gas (MMcf)	9,589	15,119	4,232	28,577
NGLs (MBbl)	211	605	304	1,307
Total combined production (MBoe)[1]	9,855	9,443	2,162	14,533
Weighted-average realized prices:				
Oil with hedges (per Bbl)	$ 59.67	$ 48.53	$ 47.40	$ 36.88
Oil without hedges (per Bbl)	$ 64.76	$ 48.05	$ 46.94	$ 35.83
Natural gas (per Mcf)	$ 2.74	$ 2.70	$ 3.42	$ 2.31
NGLs (per Bbl)	$ 26.74	$ 22.23	$ 18.20	$ 17.67
Average Benchmark prices:				
Oil (per Bbl) – Brent	$ 71.53	$ 54.65	$ 55.72	$ 45.00
Oil (per Bbl) – WTI	$ 64.76	$ 50.53	$ 53.04	$ 43.32
Natural gas (per MMBtu) – Henry Hub	$ 3.09	$ 3.00	$ 3.66	$ 2.46
Total operating expenses (per Boe)[2]	$ 18.33	$ 17.09	$ 15.72	$ 15.13
Taxes, other than income taxes (per Boe)	$ 3.36	$ 3.62	$ 2.41	$ 1.73

(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, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

(2) 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. Taxes other than income taxes are excluded from operating expenses.

(3) Production represents volumes sold during the period.

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:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
SJV South Midway Field				
Total production[2]:				
Oil (MBbls)	2,341	1,963	369	2,477
Natural gas (Bcf)	—	—	—	—
NGLs (MBbls)	—	—	—	—
Total (MBoe)[3]	2,341	1,963	369	2,477

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
SJV Belridge Hill[4]				
Total production[2]:				
Oil (MBbls)	*	609	35	*
Natural gas (Bcf)	*	—	—	*
NGLs (MBbls)	*	—	—	*
Total (MBoe)[3]	*	609	35	*

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Piceance				
Total production[2]:				
Oil (MBbls)	*	14	2	*
Natural gas (Bcf)	*	3.6	0.8	*
NGLs (MBbls)	*	—	—	*
Total (MBoe)[3]	*	610	138	*

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Hugoton basin Field[1]				
Total production[2]:				
Oil (MBbls)	*	*	*	—
Natural gas (Bcf)	*	*	*	14.6
NGLs (MBbls)	*	*	*	1,020
Total (MBoe)[3]	*	*	*	3,457

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

(1) On July 31, 2017, we sold our approximately 78% non-operated working interest in the Hugoton natural gas field. No production data is available for periods following the disposition.

(2) Production represents volumes sold during the period.

(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, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1.

(4) In July 2017, we acquired the remaining 84% working interest in the South Belridge Hill property located in Kern County, California, in which we previously owned a 16% working interest.

Productive Wells

As of December 31, 2018, we had a total of 4,029 gross (3,743 net) productive wells (including 540 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 98%. Many of our oil wells produce associated gas and some of our gas wells also produce condensate and NGLs.

The following table sets forth our productive oil and natural gas wells (both producing and capable of producing) as of December 31, 2018.

	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Oil			
Gross(1)	2,921	935	3,856
Net(2)	2,775	844	3,619
Gas			
Gross(1)	—	173	173
Net(2)	—	124	124

(1) The total number of wells in which interests are owned. Includes 540 steamflood and waterflood injection wells in California.
(2) The sum of fractional interests.

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, 2018. Approximately 75% of our leased acreage was held by production at December 31, 2018.

	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Developed(1)			
Gross(2)	11,148	95,103	106,251
Net(3)	8,212	72,944	81,156
Undeveloped(4)			
Gross(2)	120	39,366	39,486
Net(3)	120	27,182	27,302

(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

The following table sets forth our participation in wells being drilled as of December 31, 2018.

	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Development wells			
Gross	3	—	3
Net	3	—	3
Exploratory wells			
Gross	—	—	—
Net	—	—	—

At December 31, 2018, we were participating in 14 steamflood and waterflood pressure maintenance projects. 12 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)	Rockies (Uinta and Piceance basins)	Total
2018			
Oil[(2)]	224	8	232
Natural Gas	—	—	—
Dry	—	—	—
2017			
Oil[(1)]	124	—	124
Natural Gas	—	—	—
Dry	—	—	—
2016			
Oil[(1)]	11	—	11
Natural Gas	—	—	—
Dry	—	—	—

(1) Includes injector wells.
(2) Includes 40 drilled uncompleted wells in California, 12 wells that had not yet been connected to gathering systems in California and six wells that had not yet been connected to gathering systems in the Rockies.

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, 2018, the volumes contracted to be delivered were approximately 9,460 MMBtu/d of gas beginning in 2019 and will decrease over time to 4,560 MMBtu/d in 2022. We have significantly more production capacity than the amounts committed and have the ability to secure additional volumes in case of a shortfall.

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 encounter strong competition from other independent operators and master limited partnerships 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 Business 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."

Seasonality

Seasonal weather conditions can impact a portion of our drilling and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling 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 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 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. We also hedge a portion of the gas we expect to consume.

Regulation of Health, Safety and Environmental Matters

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. Our operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas industry. These laws and regulations may:

- 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;

- 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;

- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state, and private lands or leases, including preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

For example, in 2014, DOGGR began a detailed review of the multi-decade practice of permitting underground injection wells under the Safe Drinking Water Act (the "SDWA"). The purpose of the review was to ensure that wastewater is not injected into formations that could be a future source of drinking water supply. In 2015, the state set deadlines to obtain confirmation of aquifer exemptions under the SDWA in certain formations in certain fields from the United States Environmental Protection Agency (the "EPA"). Several industry groups challenged DOGGR's implementation of its aquifer exemption regulations, and, in March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcements of DOGGR's aquifer exemption regulations. The court held that DOGGR must show that an underground injection well's operations have caused an actual harm and go through a hearing process before the agency can issue fines or shut down operations.

In addition, DOGGR has proposed new underground injection regulations in July 2018. The proposed rules would impose additional requirements related to injection approvals, project data requirements, mechanical integrity testing of injection wells, monitoring requirements, prevention of surface expressions, incident response, and monitoring seismic activity. To date, restrictions on underground injection have not affected our oil and natural gas production in any material way. Separately, the state began a review in 2015 of permitted surface discharge of produced water, which led to additional permitting requirements in 2017 for surface discharge of produced water. Government authorities may ultimately restrict injection of produced water or other fluids in additional formations or certain wells, restrict the surface discharge or use of produced water or take other administrative actions. The foregoing reviews could also give rise to litigation with government authorities and third parties.

These laws, rules and regulations may also restrict the production rate of oil, natural gas and NGLs below the rate that would otherwise be possible. 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 Business 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. 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

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted three sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles, a second that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs, and a third that regulates GHG emissions from fossil fuel-burning power plants, although future implementation of this rule as it applies to existing power plants is uncertain at this time due to ongoing litigation and reconsideration of the rule by the current administration.

The EPA and the California Air Resources Board ("CARB") have also expanded direct regulation of methane emissions. In June 2016, the EPA finalized rules that establish new controls for emissions of methane (a GHG considered more potent than carbon dioxide) from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. However, in March 2018 EPA finalized several amendments to the 2016 rule, including rolling back a requirement to repair leaking components during unplanned or emergency shutdowns. Also, in September 2018, the EPA issued proposed revisions to the 2016 methane rules, which would reduce the monitoring obligations for wells and compressor stations and exempting previously covered equipment at certain locations. Separately, the U.S. Bureau of Land Management (the "BLM") previously finalized similar limitations on methane emissions from venting and flaring and leaking equipment from oil and natural gas activities on public lands, but issued a final rule repealing those standards in September 2018. Several states and environmental groups have announced their intent to file judicial challenges against any attempt to repeal or revise the EPA and BLM methane rules. As a result, future implementation of both the EPA and BLM methane rules is uncertain at this time.

Additionally, CARB has promulgated regulations regarding monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production, pipeline gathering and boosting station assets, and natural gas processing plant operations beginning in 2018 and additional controls such as vapor recovery to capture methane emissions in subsequent years. Colorado has also imposed similar regulations governing methane emissions that could impact our operations in the Piceance basin.

In addition, on September 10, 2018, the Governor of California signed into law a bill that would commit California, the fifth largest economy in the world, to the use of 100% zero-carbon electricity by 2045. The same day, the Governor also signed an executive order committing California to total economy-wide carbon neutrality by 2045, including in transportation, building heating and cooling, and industry. The law does not directly affect the oil and gas industry, and it remains unclear what actions state agencies may take in response to executive order. In any event, these recent actions could result in decreased future demand for our products to meet energy needs and in turn have an adverse effect on our business and results of operations. Legislation and regulation to address climate change could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas and other products produced by us, and potentially lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. In addition, several municipalities and counties in various states have filed lawsuits against fossil fuel energy companies to address concerns such as coastal erosion and other alleged climate-related damage.

In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in 2017 the Trump administration indicated that the United States would be withdrawing from participation in the Paris Agreement. There has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs, including by means of cap-and-trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. See "—California GHG Regulations" below for additional details on current GHG regulations in the State of California. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on or limiting emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce.

Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations. For more information, please see "Item 1A. Risk Factors—Risks Related to Our Business and Industry—Concerns about climate change and other air quality issues may affect our operations or results;" and "—Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including 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."

California GHG Regulations

In October 2006, California adopted the Global Warming Solutions Act of 2006, which established a statewide "cap-and-trade" program with an enforceable compliance obligation beginning with 2013 GHG emissions and ending in 2020. The state has also established a low carbon fuel standard that encourages the use of fuels with lower carbon intensities instead of traditional fossil fuels. In July 2017, California extended its cap-and-trade program through 2030. The program is designed to reduce the state's GHG emissions to 1990 levels by 2020 and to reduce the state's GHG emissions to at least 40% below 1990 levels by 2030. The California cap-and-trade program sets maximum limits or caps on total emissions of GHGs from industrial sectors of which we are a part, as our California operations emit GHGs. The cap will decline annually through 2030. We are required to remit compliance instruments for each metric ton of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under the cap-and-trade program, we will be granted a certain number of California carbon allowances ("CCA") and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with the California cap-and-trade program laws and regulations could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. The cost to acquire compliance instruments will depend on the market price for such instruments at the time they are purchased, the distribution of cost-free allowances among various industry sectors by the CARB and our ability to limit our GHG emissions and implement cost-containment measures.

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, the EPA has asserted federal regulatory authority pursuant to the federal SDWA over certain hydraulic stimulation activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic stimulation, and also finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic stimulation operations to publicly owned wastewater treatment plants. Further, in March 2015, the BLM adopted a rule requiring, among other things, public disclosure to the BLM of chemicals used in hydraulic stimulation operations after activity has been completed and would strengthen standards for well-bore integrity and management of fluids that return to the surface during and after stimulations on federal and Indian lands. On December 29, 2017 the BLM formally rescinded the 2015 rule governing hydraulic stimulation operations on public and tribal lands. The 2015 rule included a comprehensive set of well-bore integrity requirements, standards for the interim storage of recovered waste fluids, mandatory notifications and waiting periods for key parts of the stimulation process, and chemical disclosure requirements. On January 24, 2018, California and a coalition of environmental and tribal groups each filed lawsuits in the Northern District of California to challenge BLM's rescission of the 2015 rule. If the rule is reinstated, 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 regulatory mechanisms. In December 2016, the EPA released its final report on a wide ranging study on the effects of hydraulic stimulation on water resources. While no widespread impacts from hydraulic stimulation were found, the EPA identified a number of activities and factors that may have increased risk for future impacts.

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, certain states in which we operate have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic stimulation fluids. In addition, 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, most recently, new regulations in California requiring a permit to conduct well stimulation), bans on hydraulic stimulation in certain locations, and/or 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.

We use water in our hydraulic stimulation operations. 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. 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 (the "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. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Were the EPA to propose a rulemaking, the consent decree requires that EPA take final action by no later than July 15, 2021. 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. 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. However, in December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. Various environmental groups have filed lawsuits challenging this opinion. The ESA has not previously had a significant impact on our operations. Nevertheless, the designation of previously unprotected species 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. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standard, and separately, in December 2017, issued responses to state recommendations for designating non-attainment areas. In April 2018, the EPA issued final attainment status designations for most of the remaining portions of the United States.

State 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.

In addition, the regulations place new requirements to detect and repair volatile organic compound and methane 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.

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"). Currently, the Clean Water Rule and the scope of federal jurisdiction under the CWA are the subject of several legal challenges, and implementation of the rule has been blocked in some states. The EPA is also considering revising the scope of the 2015 rule, but any changes to the rule are likely to face judicial challenges from certain states and environmental groups. At this time we cannot predict how the original 2015 rule will be revised or whether it will be fully implemented as originally finalized. 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.

Natural Gas Sales and Transportation

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 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, 2018, 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 2019 or that will otherwise have a material impact on our financial position, results of operations or cash flows.

Employees

As of December 31, 2018, we had 322 employees.

Emergence from Chapter 11 Bankruptcy

On May 11, 2016, our predecessor company 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. Through the Chapter 11 Proceedings, the Company significantly improved its financial position from that of Berry LLC while it was owned by the Linn Entities. A final decree closing the Chapter 11 Proceedings were 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.

Corporate Information

We were incorporated in Delaware in February 2017. We have executive offices located at 5201 Truxtun Ave., Bakersfield, California 93309 and at 16000 N. Dallas Pkwy, Ste. 500, Dallas, Texas 75248, where we have our principal executive offices. Our telephone number is (661) 616-3900 and our web address is *www.berrypetroleum.com*. 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.

Risks Related to Our Business 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, our plans to return capital and other obligations and financial commitments.

Oil, natural gas and NGL prices are volatile and directly affect our results.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital, rate of growth and the carrying value of our properties. Prices for these commodities have, and may continue to, fluctuate widely in response to market uncertainty and to relatively minor changes in the supply of and demand for oil, natural gas and NGLs. For example, Brent crude oil contract prices ranged during 2018 from $62.59 per Bbl at the beginning, to a high of $86.29 per Bbl and back to $50.47 per Bbl at the end of the year. The Henry Hub spot price for natural gas also fluctuated during 2018 between $2.55 per MMBtu and $3.23 per MMBtu and are currently higher in markets where we purchase gas. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control, which include the following:

- worldwide and regional economic conditions impacting the global supply and demand for, and transportation costs of, oil and natural gas;
- the price and quantity of foreign imports of oil;
- prevailing prices on local price indexes in the areas in which we operate;
- political and economic conditions in, or affecting, other producing regions or countries, including the Middle East, Africa, South America and Russia;
- the level of global exploration, development and production, and resulting inventories;
- actions of the Organization of the Petroleum Exporting Countries ("OPEC"), its members and other state-controlled oil companies relating to oil price and production controls;
- actions of other significant producers;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and natural disasters;
- technological advances, conservation efforts and availability of alternative fuels affecting oil and gas consumption;

- refining and processing disruptions or bottlenecks;
- the impact of U.S. dollar exchange rates on oil;
- expectations about future oil and gas prices; and
- Foreign and U.S. federal, state and local and non-U.S. governmental regulation and taxes, including the recent relaxation of U.S. export restrictions.

Lower oil prices may reduce our cash flow and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected.

Also, lower prices generally adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. However, increased gas prices could negatively impact our oil reserves to the extent it made them more costly to extract. In addition, a portion of our PUDs may no longer meet the economic producibility criteria under the applicable rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, sustained periods with oil and natural gas prices at levels lower than current prices also may adversely affect our drilling economics, which may require us to postpone or eliminate all or part of our development program, and result in the reduction of some of our proved undeveloped reserves, which would reduce the net present value of our reserves.

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 make and expect to continue to make capital expenditures for the development and exploration of our oil and natural gas reserves. 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 regulatory, 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. We have a 2019 capital expenditure budget of approximately $195 million to $225 million. We expect to fund our capital expenditures with cash flows from our operations; however, our cash flows from operations, and access to capital should such cash flows 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, 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. If we are able to obtain debt financing, it would require that a portion of our cash flows from operations be used to service such indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions. 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, which in turn could lead to a decline in our reserves and production. 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.

The development of our heavy oil in California is subject to our ability to generate sufficient quantities of steam using natural gas at an economically effective cost. As a result, we need access to natural gas at prices sufficiently lower than oil prices on an energy equivalent basis to economically produce our heavy oil. 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 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 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.

We may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations, and our commodity-price risk-management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

As of December 31, 2018, we have hedged crude oil production at the following approximate volumes and prices: 17.5 MBbl/d at $70 per barrel in 2019, and 1.2 MBbl/d at $65 per barrel in 2020. In the future, we may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations.

Our current commodity-price risk-management activities may prevent us from realizing the full benefits of price increases above the levels determined under the derivative instruments we use to manage price risk. In addition, our commodity-price risk-management activities may 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 business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including 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.

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. 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 may also be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. 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 pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity requirements. The State of California has adopted additional regulations on the storage of natural gas that could affect the demand or availability of such storage, increase seasonal volatility, or otherwise affect the prices we pay for fuel gas.

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 increased fluid injection regulation and idle well decommissioning. In addition, we may experience delays, as we have in the past, due to 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.

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 “—Oil, natural gas and NGL prices are volatile and directly affect our results.”);
- production and operating costs;
- ad valorem, excise, and income 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. Reduced capital expenditures may result in a decline in our reserves. Our ability to make the necessary long-term capital expenditures or acquisitions needed to maintain or expand our reserves may be impaired to the extent cash flow from operations or external sources of capital are insufficient. We may not be successful in developing, exploring for or acquiring additional reserves. 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 are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our development, production and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable or economically desirable oil and natural gas 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; and
- 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.

Our decisions to develop or purchase prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations as well as the uncertainties of drilling noted above. For a discussion of the uncertainty involved in these processes, see "—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."

Further, many additional factors may curtail, delay or cancel our scheduled drilling projects and ongoing operations, including the following:

- delays imposed by, or resulting from, compliance with regulatory requirements, including limitations on water disposal, emission of GHGs, steam injection and well stimulation;
- pressure or irregularities in geological formations;

- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for steam used in production or pressure maintenance;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines; and
- other market limitations in our industry.

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. 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. We make assumptions that may prove inaccurate about the consistency and accuracy of data when we identify these locations. 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 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 5% of our total net acreage at December 31, 2018.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation. In addition, potential future legislation may generally affect the taxation of natural gas and oil exploration and development companies, and may adversely affect our operations.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to natural gas and oil exploration and development companies. Such legislative proposals have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. The future passage of any legislation as a result of these proposals or other changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development or otherwise significantly increase our costs.

Furthermore, in California, there have been, and currently are, proposals for new taxes on oil and natural gas production. 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.

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 for acquisitions, 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. In California, where we have the most experience operating, we have few competitors. However, most are larger than us. Our competitors may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has historically continually increased due to competition and may increase substantially in the future.

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 2019 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 variables 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, which could indirectly limit our ability to acquire assets and businesses. 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. Viable 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 24% of our steam capacity and approximately 63% 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. These facilities are dependent on viable contracts for the sale of electricity. 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. 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 existing debt agreements have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities.

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. These agreements contain covenants, that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- make investments (including certain loans to others);
- merge or consolidate with another entity;
- make dividends and certain other payments in respect of our equity;
- hedge future production or interest rates;
- create liens that secure indebtedness or certain other obligations;
- transfer, sell or otherwise dispose of assets;
- repay or prepay certain indebtedness prior to the due date;
- enter into 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 borrowing base under the RBL Facility is subject to periodic redetermination.

The amount available to be borrowed under the RBL Facility is subject to a borrowing base and will be redetermined semiannually on or about each May 1 and November 1 and will depend on the volumes of our estimated proved oil and natural gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent of, or two-thirds of the lenders under, the RBL Facility. We, and 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. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans outstanding under the facility, requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

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 were to deteriorate and remain at low levels for an extended period of time, our cash flows from operating activities may be insufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources were insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness would depend on the condition of the capital markets and our financial condition at such time, including the view of the markets of our credit risk after recent defaults. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with new covenants that further restrict business operations and opportunities. 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.

Future 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.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. 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 the year ended December 31, 2016, we recorded non-cash impairment charges of approximately $1.0 billion.

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, 2018, sales to Andeavor, Phillips 66 and Kern Oil & Refining accounted for approximately 35%, 28% and 13% respectively, of our sales.

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. This concentration of purchasers may impact our overall credit risk in that these entities 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 due to this significant customer concentration, if we were to lose any one of our major purchasers, the loss could cause us to cease or delay both production and sale of our oil and natural gas in the area supplying that purchaser.

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. Because of this geographic concentration, the success and profitability of our operations may be disproportionately influenced by conditions there. These conditions include local price fluctuations, changes in state or regional laws and regulations affecting our operations, political risks, limited acquisition opportunities where we have the most operating experience and infrastructure 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. For a discussion of regulatory risks, see "—Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including 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." The concentration of our operations in California and limited local storage options also increase our exposure to events such as natural disasters, including wildfires, mechanical failures, industrial accidents or labor difficulties.

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, refinery shutdowns and turnarounds and the ability of such facilities 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. The amount of oil, gas and NGLs that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. If our access to markets for commodities we produce is restricted, our costs could increase and our expected production growth may be impaired.

If our assets become subject to FERC regulation or federal, state or local regulations or policies change, or if we fail to comply with market behavior rules, our financial condition, results of operations and cash flows could be materially and adversely affected.

Our gathering and transportation operations are exempt from regulation by FERC, under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish that a pipeline is a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC- regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by the FERC, the courts, or Congress. If the FERC were to determine that one of our facilities or the services it provides were not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation, which could decrease revenue, increase operating costs and otherwise adversely affect our results of operations and cash flows. Should we fail to comply with any applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. The FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations in excess of $1 million per day for each violation and disgorgement of profits associated with any violation.

Moreover, FERC regulations indirectly impact our businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, gas quality, capacity release and market center promotion, indirectly affect the intrastate natural gas market.

In addition, State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, as well as complaint-based rate regulation. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, compression and sale.

For more information regarding federal and state regulation of our operations, please see "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters."

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. The Dodd-Frank Act required the Commodity Futures Trading Commission to promulgate a range of 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.

Concerns about climate change and other air quality issues may affect our operations or results.

Concerns about climate change and regulation of GHGs and other air quality issues may materially affect our business in many ways, including by increasing the costs to provide our products and services, and reducing demand for, and consumption of, the oil and gas we produce. We may be unable to recover or pass through all or any of these costs. In addition, legislative and regulatory responses to such issues may increase our operating costs and render certain wells or projects uneconomic. To the extent financial markets view climate change and GHG emissions as a financial risk, this could adversely impact our cost of, and access to, capital. Both California and the EPA have adopted laws and policies that seek to reduce GHG emissions as discussed in "Items 1 and 2. Business and Properties—Regulation of Health, Safety and Environmental Matters—Climate Change" and "—California GHG Regulations." Compliance with California cap-and-trade program laws and regulations could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. The cost of acquiring GHG emissions allowances will depend on the market price for such instruments at the time they are purchased, the distribution of cost-free allowances among various industry sectors by the California Air Resources Board, and our ability to limit GHG emissions and implement cost-containment measures. In addition, on September 10, 2018, the Governor of California signed into law a bill that would commit California to the use of 100% zero-carbon electricity by 2045. The same day, the Governor also signed an executive order committing California to total economy-wide carbon neutrality by 2045. While the law does not directly affect the oil and gas industry, and it remains unclear what actions state agencies may take in response to the executive order, these recent actions could result in decreased future demand for the oil and gas we produce and in turn have an adverse effect on our business and results of operations.

In addition, other current and proposed international agreements and federal and state laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels and electricity generation, impose additional taxes and costs on producers and consumers of petroleum products, and require or subsidize the use of renewable energy. For example, the International Maritime Organization has imposed global sulfur caps on ships sailing in emissions control areas, which are set to take effect by January 2020, and may decrease demand, or the prices we can obtain, for our products.

Governmental authorities can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act (the "CAA") and associated state laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the CAA to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region. In addition, California air quality laws and regulations, particularly in southern and central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations.

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, including well drilling, completion, stimulation, maintenance, water disposal, marketing and transportation and abandonment activities, are subject to operational 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, 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. 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. If we record inaccurate data or experience infrastructure outages, 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.

Risks Related to Emergence

Our financial condition or results of operations are not comparable to the financial condition or results of operations reflected in our historical financial statements.

Since February 28, 2017, we have been operating under a new capital structure. In addition, we adopted fresh-start accounting and, as a result, at February 28, 2017 our assets and liabilities were recorded at fair value, which resulted in values that are materially different than the values that were recorded in our historical financial statements. Accordingly, our financial condition and results of operations from and after the Effective Date are not comparable to the financial condition or results of operations reflected in our historical financial statements. Further, as a result of the implementation of the Plan and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance.

Due to our limited operating history as an independent company following our emergence from bankruptcy in February 2017, we have been in the process of establishing our accounting and other management systems and resources. We may be unable to effectively complete the development of a mature system of internal controls, and a failure of our control systems to prevent error or fraud may materially harm our company.

Our predecessor company was an indirect, wholly owned subsidiary of Linn Energy, and we utilized Linn Energy's systems, software and personnel to prepare our financial information and to ensure that adequate internal controls over financial reporting were in place. Following our emergence from bankruptcy in February 2017, we assumed responsibility for these functions. In the course of transitioning these functions, we put in place a new executive management team and continue to add personnel, upgrade our systems, including information technology, and implement additional financial and managerial controls, reporting systems and procedures. These activities place significant demands on our management, administrative and operational resources, including accounting resources, and involve risks relating to our failure to manage this transition adequately.

Proper systems of internal controls over financial accounting and disclosure controls and procedures are critical to our business. If we are unable to effectively complete the development of a mature system of internal controls, we may be unable to continue reliably assimilating and compiling financial information about our company, which would significantly impair our ability to prevent error, detect fraud or access capital markets.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Failure of our control systems to prevent error or fraud could materially adversely impact us.

Our limited operating history makes it difficult to evaluate our business plan and our long-term viability cannot be assured.

Our prospects for financial success are difficult to assess because we have a limited operating history since emergence from bankruptcy. There can be no assurance that our business will be successful, that we will be able to maintain a profitable operation, or that we will not encounter unforeseen difficulties that may deplete our capital resources more rapidly than anticipated. There can be no assurance that we will sustain profitability or positive cash flows from our operating activities.

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 Amended and Restated Certificate of Incorporation of Berry Corp. (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. In addition, our stockholders and their affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. Our business and prospects could be adversely affected if attractive business opportunities are procured by our stockholders for their own benefit rather than for ours.

Certain of our stockholders and their affiliates have resources greater than ours, which may make it more difficult for us to compete with such persons with respect to commercial activities as well as for potential acquisitions. As a result, competition from certain stockholders and their affiliates could adversely impact our results of operations.

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.

We may sell or otherwise issue additional shares of common stock or securities convertible into shares of our common stock. The Certificate of Incorporation provides that Berry Corp.'s authorized capital stock consists 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 and conditions limiting such resales expired January 21, 2019. The holders of those shares largely comprised creditors of Berry LLC prior to its bankruptcy and we cannot predict when or whether they will sell such shares. Such sales, or concerns about them, may put downward pressure on the market price of our common stock.

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 Berry Petroleum Corporation 2017 Omnibus Incentive Plan, as amended and restated (our "Restated Incentive 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 Restated Incentive 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 Restated Incentive Plan 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 the common stock.

We are an "emerging growth company," and are able 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.

"Emerging growth companies" can also delay adopting new or revised accounting standards until such time as those standards apply to private companies. 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 under Section 107 of the JOBS Act until we are no longer 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 pursuant to Section 107 of the JOBS Act.

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.

We will incur significant costs and devote substantial management time as a result of operating as a public company, particularly after we are no longer an "emerging growth company."

Our management and other personnel are required to divert attention from operational and other business matters to devote substantial time to public company requirements. After we no longer qualify as an "emerging growth company," we expect to incur additional management time and cost to comply with the more stringent reporting requirements applicable to companies that are deemed accelerated filers or large accelerated filers, including complying with the auditor attestation requirements of Section 404(b) of the Sarbanes-Oxley Act. We currently do not have an internal audit function, and we have needed, and will continue to need, to hire or contract for additional accounting and financial staff with appropriate public company experience and technical accounting knowledge.

If we do not adequately develop or maintain all required financial reporting and disclosure procedures and controls, we may be unable to provide the financial information required of a U.S. publicly traded company in a timely and reliable manner.

As a private company we were not required to adopt or maintain all of the financial reporting and disclosure procedures and controls required of a U.S. publicly traded company. If we fail to adequately develop and maintain effective internal controls and procedures and disclosure procedures and controls, we may be unable to provide the financial information and SEC reports that a U.S. publicly traded company is required to provide in a timely and reliable fashion. Any such delays or deficiencies could penalize us, including by limiting our ability to obtain financing, either in the public capital markets or from private sources and hurt our reputation and could thereby impede our ability to implement our growth strategy.

Our internal control over financial reporting is not currently required to meet 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 in the future could have a material adverse effect on our business and share price.

Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal control over financial reporting, starting with the second annual report that we file with the SEC after the consummation of the IPO, and generally requires a report by our independent registered public accounting firm on the effectiveness of our internal control over financial reporting. However, under the JOBS Act, 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, prevent fraud and operate successfully as a public company. 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.

In connection with the implementation of the necessary procedures and practices related to internal control over financial reporting, we may identify deficiencies that we may not be able to timely remediate. In addition, we may encounter problems or delays in completing the implementation of any remediation of control deficiencies and receiving a favorable attestation in connection with the attestation provided by our independent registered public accounting firm. 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 the Certificate of Incorporation and Bylaws, as well as our stockholders agreement, 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 the Form of the Second Amended and Restated Bylaws of Berry Corp. (the "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 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. Additionally, we and many of the largest holders of our equity securities are bound by a stockholders agreement that requires us to nominate for election and take all other necessary actions to cause an individual designated by Benefit Street Partners to be included in the slate of nominees recommended by the board of directors to be elected to the board of directors.

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. Any person or entity purchasing or otherwise acquiring any interest in shares of our common stock will be deemed to have notice of, and consented to, the provisions of our Certificate of Incorporation described in the preceding sentence. 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.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

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.

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—Lawsuits, Claims, 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 began trading on the NASDAQ under the ticker symbol "BRY" on July 26, 2018. Prior to that, there was no public market for our common stock.

Holders of Record

Our common stock was held by 102 stockholders of record at January 31, 2019, and by approximately 2,100 additional stockholders whose shares were held for them in street name or nominee accounts.

Dividend Policy

We plan to use our operating cash flows to cover our interest requirements, fund our maintenance capital requirements, and consistently return meaningful capital to stockholders through quarterly dividends. 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.

Securities Authorized for Issuance Under Equity Compensation Plans

On June 27, 2018, our Board approved the Second Amended and Restated Berry Petroleum Corporation 2017 Omnibus Incentive Plan (the "Omnibus Plan"). A description of the plans can be found in Item 8. Financial Statements and Supplementary Data – Note 8–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 approximately 1.6 million have been issued or reserved through December 31, 2018.

The following table summarizes information related to our equity compensation plans under which our equity securities are authorized for issuance as of December 31, 2018.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights (#)[3]	Weighted-Average Exercise Price of Outstanding Options and Rights ($)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (#)[1]
Equity compensation plans not approved by security holders[2]	922,952	N/A	8,381,902

(1) The number of securities remaining available for future issuances has been reduced by the number of securities to be issued upon RSUs subject to time vesting and PSUs upon the 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) Represents common stock to be issued based upon continuous employment and the maximum achievement of certain performance goals over a specified period of time as described in the applicable Equity Compensation Plan and associated award agreements. We did not have any options or rights with an exercise price.

Sales of Unregistered Securities

Between January 1, 2018 and August 3, 2018, we issued 895,422 RSUs and 754,539 PSUs to certain of our employees and directors in connection with services provided to us, which issuances were not registered under the Securities Act of 1933, as amended (the "Securities Act"). In connection with our IPO, on August 3, 2018, we filed a Registration Statement on Form S-8 registering future issuances of common stock underlying our RSUs and PSUs.

The offers, sales and issuances of the securities described in the preceding paragraph were deemed to be exempt from registration either under Rule 701 promulgated under the Securities Act in that the transactions were under compensatory benefit plans and contracts relating to compensation, or under Section 4(a)(2) of the Securities Act in that the transactions were between an issuer and members of its senior executive management and did not involve any public offering within the meaning of Section 4(a)(2).

In February 2019, we issued and sold 350,000 shares of our common stock to Berry LLC at par value for aggregate consideration of $350, and Berry LLC agreed to issue those shares on our behalf in satisfaction of any liability arising from the remaining unsecured claim pending related to the Chapter 11 Proceeding. The shares were issued pursuant to an exemption from registration under Section 1145(a) of the U.S. Bankruptcy Code.

On February 8, 2018, we completed the 2026 Notes offering. The 2026 Notes were issued at a price of 100% of par, and the sale resulted in net proceeds (after deducting the initial purchasers' discounts and commissions and estimated offering expenses and excluding accrued interest) to the Company of approximately $391 million. We used the net proceeds to repay borrowings under our RBL Facility and for general corporate purposes.

The 2026 Notes were issued and sold to the initial purchasers in a private placement exempt from the registration requirements of the Securities Act. The initial purchasers sold the 2026 Notes to qualified institutional buyers inside the United States in reliance on Rule 144A of the Securities Act and to persons outside the United States under Regulation S of the Securities Act.

Stock Repurchase Program

On December 13, 2018, our Board of Directors announced it had adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of current market conditions for our common stock they authorized current repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. 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 Petroleum to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. In December 2018, we repurchased 448,661 shares at an average price of $8.81 per share. The Company repurchased 1,932,096 shares from January 1, 2019 through February 28, 2019, resulting in a total of 2,380,757 shares repurchased under the Stock Repurchase Program as of February 28, 2019.

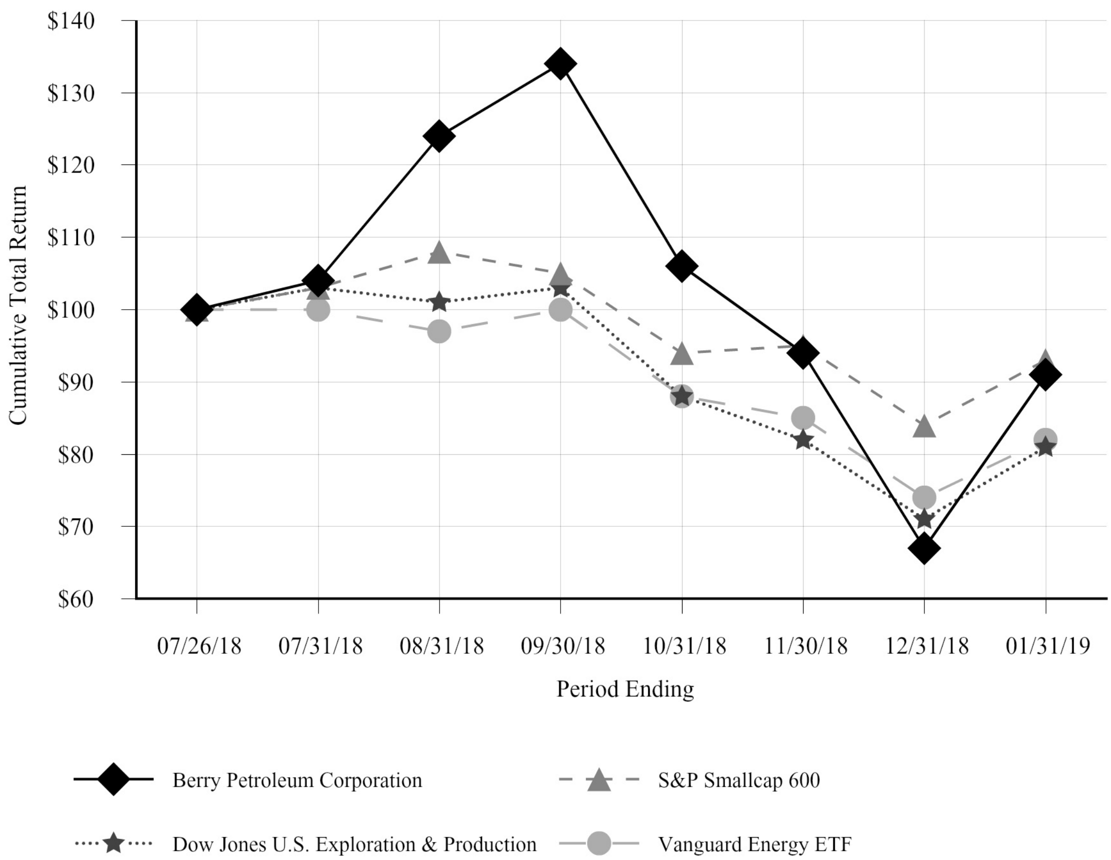
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
December 1 - 31, 2018	448,661	$ 8.81	448,661	$ 46,047,000

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 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 6 MONTH CUMULATIVE TOTAL RETURN(1)(2)

Among Berry Petroleum Corporation, the S&P Smallcap 600 Index,
the Dow Jones U.S. Exploration & Production Index
and the Vanguard Energy ETF



	07/26/18	07/18	08/18	09/18	10/18	11/18	12/18	01/19
Berry Petroleum Corporation	$ 100.00	$ 103.77	$ 123.70	$ 133.73	$ 106.25	$ 94.04	$ 67.17	$ 90.51
S&P Smallcap 600	$ 100.00	$ 103.16	$ 108.15	$ 104.71	$ 93.74	$ 95.15	$ 83.66	$ 92.56
Dow Jones U.S. Exploration & Production	$ 100.00	$ 103.39	$ 100.56	$ 102.81	$ 88.00	$ 82.46	$ 71.18	$ 80.76
Vanguard Energy ETF	$ 100.00	$ 100.06	$ 97.10	$ 99.64	$ 87.58	$ 85.09	$ 73.67	$ 82.30

(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 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, 2016 and as of and for the two months ended February 28, 2017 is derived from the audited historical financial statements of our predecessor company. The selected historical financial information as of and for the ten months ended December 31, 2017 and as of and for the year ended December 31, 2018 is derived from audited consolidated financial statements of the successor company.

Upon Berry LLC's emergence from bankruptcy on February 28, 2017, or the Effective Date, in connection with the Plan, 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. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. These fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our predecessor company's historical balance sheet. The effects of the Plan and the application of fresh-start accounting are reflected in Berry Corp.'s consolidated financial statements as of the Effective Date and the related adjustments thereto are recorded in our consolidated statements of operations as reorganization items for the periods prior to the Effective Date. 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. You should read the following table in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," the historical financial statements of our predecessor and accompanying notes included elsewhere in this report.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	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	$ 586,557	$ 319,669	$ 92,718	$ 410,991
Net income (loss)	$ 147,102	$ (21,068)	$ (502,964)	$ (1,283,196)
Net income (loss) attributable to common stockholders	$ 49,160	$ (39,316)	n/a	n/a
Net income (loss) per share of common stock				
Basic	$ 0.85	$ (1.02)	n/a	n/a
Diluted	$ 0.85	$ (1.02)	n/a	n/a
Dividends per common share	$ 0.21	$ —	$ —	$ —
Weighted-average common stock outstanding				
Basic	57,743	38,644	n/a	n/a
Diluted(1)	57,932	38,644	n/a	n/a
Cash Flow Data:				
Operating activities(2)	$ 103,100	$ 107,399	$ 22,431	$ 13,197
Capital expenditures	$ (127,281)	$ (65,479)	$ (3,158)	$ (34,796)
Balance Sheet Data (at period end):				
Total assets	$ 1,692,263	$ 1,546,402	$ 1,561,038	$ 2,652,050
Long-term debt, net	$ 391,786	$ 379,000	$ 400,000	$ —
Other Financial Data:				
Adjusted EBITDA(3)	$ 257,924	$ 149,613	$ 28,845	$ 89,646
Adjusted Net Income (Loss)(4)	$ 100,001	$ 35,880	$ (7,779)	$ (149,961)

(1) 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 earnings per share calculation for the year ended December 31, 2018 and the ten months ended December 31, 2017 as their effect was antidilutive under the "if-converted" method. In July 2018, all outstanding shares of our Series A Preferred Stock were converted to common shares in connection with the IPO. Please see Note 8 for further detail.

(2) 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 NYMEX WTI to ICE Brent underlying.

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures."

(4) Adjusted Net Income is a non-GAAP financial measure. For a definition of Adjusted Net Income and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures."

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."

Executive Overview

We are a western United States independent upstream energy company with a focus on the conventional, long-lived oil reserves in the San Joaquin basin of California. Our long-lived, high-margin asset base is uniquely positioned to support our objectives of generating top-tier corporate-level returns and positive levered free cash flow through commodity price cycles. We target onshore, low-cost, low-risk, oil-rich reservoirs in the San Joaquin basin of California and, to a lesser extent, our Rockies assets including low-cost, oil-rich reservoirs in the Uinta basin of Utah and low geologic risk natural gas resource plays in the Piceance basin in Colorado. Successful execution of our strategy across our low-declining production base and extensive inventory of identified drilling locations will result in long-term, capital efficient production growth as well as the ability to continue returning capital to our stockholders.

How We Plan and Evaluate Operations

We use Levered Free Cash Flow to plan our capital allocation for maintenance and internal growth opportunities as well as hedging needs. We define Levered Free Cash Flow as Adjusted EBITDA less interest expense, dividends, and capital expenditures.

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. We define Adjusted EBITDA 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, including gains and losses on sale of assets, restructuring costs and reorganization items.

Operating expenses

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. 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. Overall, operating expense is used by management as a measure of the efficiency with which operations are performing.

Environmental, health & safety

We are committed to good corporate citizenship in our communities, operating safely and protecting the environment and our employees. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics is a part of our incentive programs for all employees.

General and administrative expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

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.

Emergence from Chapter 11 Bankruptcy

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. Through the Chapter 11 Proceedings, the Company significantly improved its financial position from that of Berry LLC while it was owned by the Linn Entities. A final decree closing the Chapter 11 Proceedings were 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. After the Effective Date we have negotiated with claimants to settle their claims. 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.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Basis of Presentation and Fresh-Start Accounting

Upon Berry LLC's emergence from bankruptcy, we adopted fresh-start accounting, which, with the recapitalization upon emergence from bankruptcy, resulted in Berry Corp. becoming the financial reporting entity in our corporate group.

Unless otherwise noted or suggested by context, all financial information and data and accompanying financial statements and corresponding notes, as contained in this report, on or prior to the Effective Date, reflect the actual historical results of operations and financial condition of our predecessor company for the periods before and after the Effective Date and do not give effect to the Plan or any of the transactions contemplated thereby or the adoption of fresh-start accounting. Following the Effective Date, they reflect the actual historical results of operations and financial condition of Berry Corp. on a consolidated basis and give effect to the Plan and any of the transactions contemplated thereby and the adoption of fresh-start accounting. Thus, the financial information presented herein on or prior to the Effective Date is not comparable to Berry Corp.'s performance or financial condition after the Effective Date. As a result, "black-line" financial statements are presented to distinguish between Berry LLC as the predecessor and Berry Corp. as the successor.

Berry Corp.'s financial statements reflect the application of fresh-start accounting under GAAP. GAAP requires that the financial statements, for periods subsequent to the Chapter 11 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 Berry Corp.'s as well as Berry LLC's statements of operations. In addition, Berry Corp.'s balance sheet classifies the cash distributions from a $35 million cash distribution pool (the "Cash Distribution Pool") as "liabilities subject to compromise." Pre-petition unsecured and under-secured obligations that were affected by the bankruptcy reorganization process have been classified as "liabilities subject to compromise" on our balance sheet and our predecessor company's balance sheet.

Reorganization and Financing Activities

The main actions we took affecting comparability between periods before and after the Effective Date include the reorganization of Berry LLC through bankruptcy and resulting substantial elimination of debt, entry into the RBL Facility, issuance of the 2026 Notes, dividends on and conversion of Series A Preferred Stock and completion of the IPO. These actions are described below in "—Liquidity and Capital Resources."

Capital Expenditures and Capital Budget

Immediately following Berry LLC's emergence from bankruptcy and separation from the Linn Entities in 2017, we increased our pace of development and have continued to do so throughout 2018. For the years ended December 31, 2018 and 2017, our capital expenditures were approximately $148 million and $73 million, respectively, on an accrual basis excluding acquisitions. Our 2019 anticipated capital expenditure budget is approximately $195 to $225 million, which represents an increase of approximately 42% over 2018 capital expenditures. Capital expenditures increased 103% from 2017 to 2018. Based on current commodity prices and a drilling success rate comparable to our historical performance, we believe we will be able to fund our 2019 capital development programs while producing positive Levered Free Cash Flow. Our 2019 capital program is focused on growing our oil production in California. We anticipate oil production will be approximately 86% of total production in 2019, compared to 82% in 2018. This change in product mix also factors in the divestiture of our non-core East Texas gas properties in late 2018. During 2019, we expect to:

- employ four drilling rigs in California throughout the year; and
- drill approximately 370 to 420 gross development wells, all of which we expect will be in California for oil production.

The table below sets forth the expected allocation of our 2019 capital expenditure budget by area as compared to the allocation of our 2018 and 2017 capital expenditures.

	2019 Budget	2018 Actual	2017 Actual
		(in millions)	
California	$ 185-212	$ 126	$ 71
Rockies	4-6	17	2
Corporate	6-7	5	—
Total	$ 195-225	$ 148	$ 73

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these 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 availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. 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.

Acquisitions and Divestitures

Acquisition of Hill Properties

On July 31, 2017, we acquired the remaining 84% working interest in the South Belridge Hill property located in Kern County, California, in which we previously owned a 16% working interest (the "Hill Acquisition"). We purchased the properties for approximately $249 million.

Chevron North Midway-Sunset Acquisition

In April 2018, we acquired two leases on an aggregate of 214 acres and a lease option on 490 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 $34.5 million to drill 115 wells on or before April 1, 2020, which we extended to April 1, 2022. 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. We had not drilled any of these wells as of December 31, 2018. We would assume an additional 40 well drilling commitment if we exercise our option on the 490 acres. We paid no other consideration for the acquisition. Our 2019 anticipated capital expenditure budget currently includes approximately $16 million to drill 33 out of these 115 wells. This transaction is consistent with our business strategy to investigate areas beyond our known productive areas.

Disposition of Hugoton Properties

On July 31, 2017, we divested our 78% working interest in the Hugoton natural gas field located in Southwest Kansas and the Oklahoma Panhandle (the "Hugoton Disposition") because we deemed it a non-core asset. This resulted in approximately $234 million of proceeds and a $23 million gain.

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.

Commodity Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices. We target covering our operating expenses and fixed charges, including maintenance capital expenditures, for up to two years out. We have hedged a portion of our exposure to differentials between Brent and WTI as well. 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.

As of February 28, 2019, our hedge position consisted of oil swaps and puts and natural gas swaps. We use oil swaps and puts to protect against decreases in the oil price and natural gas swaps to protect against increases in natural gas 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.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our put positions, we paid the premium at the time the positions were created, and for others, we will pay the premium at the time of settlement. In order to mitigate the exposure to these deferred premiums, we have entered into several offsetting put positions. Swap contracts are designed to provide a fixed price. For fixed-price swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel of our contracts and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel. For fixed-price natural 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.

In January and February 2019, we closed a portion of our deferred premium put positions by selling offsetting put positions and terminating contracts. We also added to our natural gas swap positions we had previously hedged. As of February 28, 2019, we had hedged approximately 15.3 MBbl/d of our 2019 crude oil production at $68 per barrel, as outlined in the following table along with our natural gas derivative contracts:

	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Net Purchased/Sold Oil Put Options (ICE Brent):				
Hedged volume (MBbls)	484	1,365	368	368
Weighted-average price ($/Bbl)	$ 61.16	$ 61.00	$ 50.00	$ 50.00
Fixed Price Oil Swaps (ICE Brent):				
Hedged volume (MBbls)	1,080	637	644	644
Weighted-average price ($/Bbl)	$ 75.76	$ 76.27	$ 76.27	$ 76.27
Oil basis differential positions (ICE Brent-NYMEX WTI basis swaps):				
Hedged volume (MBbls)	45	46	46	46
Weighted-average price ($/Bbl)	$ (1.29)	$ (1.29)	$ (1.29)	$ (1.29)
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	1,815,000	2,730,000	1,380,000	465,000
Weighted-average price ($/MMBtu)	$ 2.68	$ 2.70	$ 2.65	$ 2.65

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Crude Oil (per Bbl):				
Realized price, before the effects of derivative settlements	$ 64.76	$ 48.05	$ 46.94	$ 35.83
Effects of derivative settlements	$ (5.09)	$ 0.48	$ 0.46	$ 1.05

We expect our operations to generate substantial cash flows at current commodity prices. We have protected a portion of our anticipated cash flows through 2020 as part of our crude oil hedging program. Our low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production.

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 and Brent oil purchased put options for January 2019 through March 2020. The Brent oil swaps hedged 1.8 MMBbls in 2018 and 0.9 MMBbls in 2019 at a weighted-average price of $75.66. The Brent oil purchased put options provided a weighted-average price floor of $65.00 for 2.8 MMBbls in 2019 and 0.5 MMBbls in 2020. We effected these transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with current market pricing.

Taxes, other than income taxes

Taxes, other than income taxes includes severance taxes, ad valorem and property taxes, GHG allowances, and other taxes not based on income. We include these taxes when analyzing the economics of development projects and the efficiency of our hydrocarbon recovery; however, we do not include these taxes in our operating expenses.

Income Taxes

Prior to the Effective Date, Berry LLC was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, Berry LLC was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of Berry LLC. Upon emergence from bankruptcy, Berry Corp. acquired the assets of Berry LLC in a taxable asset acquisition as part of the restructuring. Consequently, we are now taxed as a corporation and have no net operating loss carryforwards for the periods prior to February 28, 2017.

On December 22, 2017, the U.S. Tax Cuts and Jobs Act (the "Act") made significant changes to the Internal Revenue Code of 1986, including lowering the maximum federal corporate income tax rate from 35% to 21% and imposing limitations on the use of net operating losses arising in taxable years ending after December 31, 2017. The Securities and Exchange Commission ("SEC") permitted the recognition of provisional amounts based on a reasonable estimate, subject to adjustments in a one-year measurement period. For the year ended December 31, 2017, we recorded provisional estimates for the remeasurement of our net deferred tax asset before valuation allowance of $2.7 million for the reduction in the corporate tax rate and a $1.9 million increase in the valuation allowance as a result of the Act. During 2018, we completed our accounting related to the income tax effects of the Act, resulting in no significant adjustments to the provisional amounts recorded.

The key contributor to the change in our effective rate from (15)% in the ten months ended December 31, 2017 to 23% for the year ended December 31, 2018 was the reduction in our valuation allowance. Our earnings for 2018 allowed for the release of our valuation allowance, described below, resulting in an effective tax rate less than the statutory federal and state tax rates.

Business Environment and Market Conditions

The oil and gas industry is heavily influenced by commodity prices. While oil prices improved in 2018 compared to 2017 and 2016, they did fluctuate during the year. Brent crude oil contract prices ranged during 2018 from $62.59 per Bbl at the beginning, to a high of $86.29 per Bbl and back to $50.47 per Bbl at the end of the year. The Henry Hub spot price for natural gas also fluctuated during 2018 between $2.55 per MMBtu and $3.23 per MMBtu. Our revenue, costs, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production and the prices we pay for our natural gas purchases which will continue to be affected by a variety of factors. Please see "Item 1A. Risk Factors—Risks Related to Our Business and Industry—Oil, natural gas and NGL prices are volatile and directly affect our results."

The following table presents the average ICE Brent, NYMEX WTI oil and NYMEX Henry Hub natural gas prices for the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
ICE (Brent) oil ($/Bbl)	$ 71.53	$ 54.65	$ 55.72	$ 45.00
NYMEX (WTI) oil ($/Bbl)	$ 64.76	$ 50.53	$ 53.04	$ 43.32
NYMEX (Henry Hub) natural gas ($/MMBtu)	$ 3.09	$ 3.00	$ 3.66	$ 2.46

California oil prices are Brent-influenced as California refiners import more than 50% of the state’s demand from foreign sources, primarily the Middle East and South America. There is a closer correlation of prices in California to Brent pricing than to WTI. Without the higher costs 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, will allow us to continue to realize strong cash margins in California.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for oil's unique 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, as well as availability of transportation capacity from producing areas. We use substantially more natural gas for our steamfloods and power generation, than we produce and sell. Consequently, higher gas prices have a negative impact on our operating costs. However, we mitigate a substantial portion of this exposure by selling excess electricity from our cogeneration operations to third parties. Also, the negative impact of higher gas prices is partially offset by higher gas sales for the gas we produce.

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. The most significant input and cost of the cogeneration facilities is natural gas. The price we receive from selling electricity to third–parties is closely tied to the price of natural gas and thus these operations effectively serve as a partial hedge against gas price increases.

Certain Operating and Financial Information

The following tables set forth information regarding total production, average daily production, average prices and average costs for the year ended December 31, 2018 compared to the year ended December 31, 2017, including the successor and predecessor periods, and the year ended December 31, 2016. The information for the year ended December 31, 2017 is reflected in the tables and narrative discussion that follows in two distinct periods, the ten months ended December 31, 2017 and the two months ended February 28, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to the year ended December 31, 2017 are used to provide comparable periods. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods before and after the Effective Date.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Average daily production[1]:				
Oil (MBbl/d)	22.0	20.6	19.5	23.1
Natural Gas (MMcf/d)	26.3	49.4	71.7	78.1
NGLs (MBbl/d)	0.6	2.0	5.2	3.6
Total (MBoe/d)[2]	27.0	30.9	36.7	39.7
Total Production:				
Oil (MBbl)	8,045	6,318	1,153	8,463
Natural gas (MMcf)	9,589	15,119	4,232	28,577
NGLs (MBbl)	211	605	304	1,307
Total (MBoe)[2]	9,855	9,443	2,162	14,533
Weighted-average realized prices:				
Oil with hedges (Bbl)	$ 59.67	$ 48.53	$ 47.40	$ 36.88
Oil without hedges (Bbl)	$ 64.76	$ 48.05	$ 46.94	$ 35.83
Natural gas (Mcf)	$ 2.74	$ 2.70	$ 3.42	$ 2.31
NGLs (Bbl)	$ 26.74	$ 22.23	$ 18.20	$ 17.67
Average Benchmark prices:				
Oil (Bbl) – Brent	$ 71.53	$ 54.65	$ 55.72	$ 45.00
Oil (Bbl) – WTI	$ 64.76	$ 50.53	$ 53.04	$ 43.32
Natural gas (MMBtu) – Henry Hub	$ 3.09	$ 3.00	$ 3.66	$ 2.46
Average costs per Boe[3]:				
Lease operating expenses	$ 19.16	$ 15.84	$ 13.06	$ 12.73
Electricity generation expenses	2.09	1.58	1.48	1.18
Electricity sales[3]	(3.57)	(2.33)	(1.69)	(1.60)
Transportation expenses	1.00	2.04	2.86	2.86
Transportation sales[3]	(0.08)	—	—	—
Marketing expenses	0.22	0.25	0.30	0.21
Marketing revenues[3]	(0.24)	(0.29)	(0.29)	(0.25)
Derivative settlements (received) paid for gas purchases[3]	(0.24)	—	—	—
Total operating expenses	$ 18.33	$ 17.09	$ 15.72	$ 15.13
General and administrative expenses[4]	$ 5.48	$ 5.93	$ 3.68	$ 5.45
Depreciation, depletion and amortization	$ 8.75	$ 7.25	$ 13.02	$ 12.26
Taxes, other than income taxes	$ 3.36	$ 3.62	$ 2.41	$ 1.73

(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.

(3) 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 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 includes the effect of derivative settlements (received or paid) for gas purchases.

(4) Includes non-recurring restructuring and other costs and non-cash stock compensation expense, in aggregate, of approximately $1.36 per Boe and $3.40 per Boe for the year ended December 31, 2018 and the ten months ended December 31, 2017, respectively, and none for each of the two months ended February 28, 2017 and the year ended December 31, 2016.

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	**Ten Months Ended December 31, 2017**	**Two Months Ended February 28, 2017**	**Year Ended December 31, 2016**
Average daily production (MBoe/d)[1]:				
California[2]	19.7	18.0	17.0	20.2
Rockies[4]	7.3	8.4	8.8	10.0
Hugoton basin[3]	—	4.5	10.8	9.5
Total average daily production	27.0	30.9	36.7	39.7

(1) Production represents volumes sold during the period.
(2) On July 31, 2017, we purchased the remaining approximately 84% working interest of our South Belridge Hill property, located in Kern County, California.
(3) On July 31, 2017, we sold our 78% working interest in the Hugoton natural gas field located in southwest Kansas and the Oklahoma Panhandle. Our Hugoton assets represented approximately 24% of our average net daily production for the year ended December 31, 2016.
(4) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

We allocated predominantly all of our 2018 capital to develop California's oil properties which experienced an 11% or 1.9 MBoe/d increase in 2018 production compared to 2017. This included a 1.5 MBoe/d year-over-year increase due to the Hill Acquisition. The 2018 development activities accelerated our California production growth throughout the year, resulting in an 11% increase from 19.5 MBoe/d in the three months ended December 31, 2017 to 21.7 MBoe/d in the three months ended December 31, 2018.

The year-over-year Rockies production decline, predominantly gas, was largely due to our decision to allocate most of the 2018 capital to California development. The challenging market conditions in the Uinta basin due to limited local oil demand and takeaway capacity further contributed to this reduction. We also sold our East Texas gas properties in November 2018. Finally, our 2018 production was approximately 5.6 MBoe/d lower than 2017 due to the Hugoton Disposition in July 2017.

The impact of our California oil-focused capital program, as well as the Hill Acquisition (100% oil) and Hugoton Disposition (100% natural gas) in 2017, was an increase in oil production to 82% of total production in the year ended December 31, 2018 from 64% of total production in the year ended December 31, 2017.

Average daily production volumes decreased in 2017, including the successor ten months ended December 31, 2017 and the predecessor two months ended February 28, 2017, by 7.9 MBoe/d or 20% when compared to the year ended December 31, 2016, primarily due to reduced development capital spending in 2016 and early 2017 and the Hugoton Disposition in July 2017, partially offset by the additional oil volumes from the Hill Acquisition in July 2017.

Summary by Area

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated. Full year data for 2017 are presented as a single amount for simplicity, but represent two distinct periods, the two months ended February 28, 2017 (our predecessor) and the ten months ended December 31, 2017 (our successor).

	California (San Joaquin and Ventura basins)		Rockies (Uinta and Piceance basins)	
($ in thousands, except prices)	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
Total revenues	$ 471,983	$ 311,247	$ 76,855	$ 76,365
Operating income[1]	$ 226,854	$ 74,629	$ 19,089	$ 9,961
Depreciation, depletion, and amortization	$ 72,260	$ 71,092	$ 11,066	$ 17,792
Average daily production (MBoe/d)	19.7	17.8	6.7	7.4
Production (oil% of total)	100%	100%	36%	36%
Realized prices:				
Oil (per Bbl)	$ 65.64	$ 47.79	$ 57.34	$ 48.47
NGLs (per Bbl)	$ —	$ —	$ 26.95	$ 21.36
Gas (per Mcf)	$ —	$ —	$ 2.71	$ 2.78
Capital expenditures	$ 125,565	$ 63,313	$ 17,351	$ 1,451
Total proved reserves (MMBoe)	106	93	37	46
PV-10[2]	$ 2,026,880	$ 998,391	$ 124,652	$ 108,375

(1) Operating income includes oil, natural gas and NGL sales, offset by operating expenses, general and administrative expenses, DD&A, and taxes, other than income taxes.
(2) 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 "Items 1 and 2. Business and Properties—Our Reserves and Production Information".

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Results of Operations

Results of Operations - Year ended December 31, 2018, Ten Months Ended December 31, 2017, and Two Months Ended February 28, 2017

Our results of operations for the year ended December 31, 2017 are reflected in the tables and narrative discussion that follows in two distinct periods, the two months ended February 28, 2017 and the ten months ended December 31, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to "the change" and "the percentage change" compare the year ended December 31, 2018 results to the combined results for the comparison period in 2017 in order to provide comparability of such information. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods before and after the Effective Date.

	Berry Corp. (Successor)		Berry LLC (Predecessor)		
	(c) Year Ended December 31, 2018	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c)-((a)+(b)) Change	% Change
			(in thousands)		
Revenues and other:					
Oil, natural gas and NGL sales	$ 552,874	$ 357,928	$ 74,120	$ 120,826	28 %
Electricity sales	35,208	21,972	3,655	9,581	37 %
Gains (losses) on oil derivatives	(4,621)	(66,900)	12,886	49,393	(91)%
Marketing revenues	2,322	2,694	633	(1,005)	(30)%
Other revenues	774	3,975	1,424	(4,625)	(86)%
Total revenues and other	586,557	319,669	92,718	174,170	42 %
Expenses:					
Lease operating expenses	188,776	149,599	28,238	10,939	6 %
Electricity generation expenses	20,619	14,894	3,197	2,528	14 %
Transportation expenses	9,860	19,238	6,194	(15,572)	(61)%
Marketing expenses	2,140	2,320	653	(833)	(28)%
General and administrative expenses	54,026	56,009	7,964	(9,947)	(16)%
Depreciation, depletion and amortization	86,271	68,478	28,149	(10,356)	(11)%
Taxes, other than income taxes	33,117	34,211	5,212	(6,306)	(16)%
(Gains) losses on natural gas derivatives	(6,357)	—	—	(6,357)	(100)%
(Gains) losses on sale of assets and other, net	(2,747)	(22,930)	(183)	20,366	(88)%
Total expenses and other	385,705	321,819	79,424	(15,538)	(4)%
Other income (expenses):					
Interest expense	(35,648)	(18,454)	(8,245)	(8,949)	34 %
Other, net	243	4,071	(63)	(3,765)	(94)%
Reorganization items, net	24,690	(1,732)	(507,720)	534,142	(105)%
Income (loss) before income taxes	190,137	(18,265)	(502,734)	711,136	(136)%
Income tax expense (benefit)	43,035	2,803	230	40,002	1,319 %
Net income (loss)	147,102	(21,068)	$ (502,964)	$ 671,134	(128)%
Series A Preferred Stock dividends and conversion to common stock	(97,942)	(18,248)	n/a	n/a	n/a
Net income (loss) attributable to common stockholders	$ 49,160	$ (39,316)	n/a	n/a	n/a

Revenues and Other

Oil, natural gas and NGL sales increased in 2018 by $121 million or 28% when compared to the year ended December 31, 2017, including the successor and predecessor periods. The increase was primarily due to increased oil production in California and higher realized oil prices, partially offset by lower gas and NGL production. Oil production in the Rockies was adversely impacted as we managed storage to address the extended shutdown of a major refinery in the area which limited sales and negatively impacted production. The net effect of the Hill Acquisition and Hugoton Disposition in 2017 resulted in lower total production on an oil equivalent basis but helped to increase oil volumes and the relative mix of oil production, resulting in a $39 million increase in revenues. Our organic oil production growth from our 2018 capital program also contributed to increased revenues.

Electricity sales represents sales to utilities which increased in 2018 by $10 million or 37% when compared to the year ended December 31, 2017, including the successor and predecessor periods, primarily due to higher prices, attributed to higher natural gas costs, and higher volumes sold externally because of increased utilization at our cogeneration facilities.

Losses on oil derivatives were $4.6 million, a decrease of $49 million or 91% when compared to the year ended December 31, 2017, including the successor and predecessor periods. Our losses in 2018 were due to the mark-to-market losses incurred on oil derivatives prior to being terminated in May 2018 and settled with a $127 million payment. We terminated these derivatives and entered into new hedges to better align our hedge pricing with the then-prevailing market pricing. These early-2018 losses were offset by gains on oil derivatives in the latter portion of the year, primarily due to the decline in oil prices in the fourth quarter compared to the higher hedge pricing.

Marketing revenues, which primarily represent sales of natural gas purchased from third-parties, decreased in 2018 compared to the year ended December 31, 2017, including the successor and predecessor periods, due to lower sales volume.

Other revenues decreased in 2018 by $5 million or 86% when compared to the year ended December 31, 2017, including the successor and predecessor periods. Other revenues in 2017 primarily consisted of helium sales, all of which were derived from our Hugoton assets prior to their disposition in July 2017.

Expenses

Operating expenses includes 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. Operating expenses for 2018 increased to $18.33 per Boe from $16.84 for the year ended December 31, 2017, including the successor and predecessor periods. The increase was primarily driven by an increase in lease operating expenses per Boe, partially offset by an increase in the gross margin for our electricity sales, as discussed below.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses per Boe increased by 25% to $19.16 per Boe for the year ended December 31, 2018 from $15.32 per Boe in 2017, including the successor and predecessor periods. The increase was primarily due to the change in the mix of our products from 64% oil in 2017 to 82% in 2018. Our oil production is more costly than gas production, but also generates more margin per barrel. The change in product mix was driven by the Hugoton Disposition (natural gas production) and Hill Acquisition (oil production) in July 2017, as well as the oil production growth from capital expenditures during 2018. Lease operating expenses in absolute dollars increased in 2018 by $11 million or 6% when compared to the year ended December 31, 2017, including the successor and predecessor periods. The increase reflected higher fuel gas costs (mostly due to more volumes purchased), and increased facility maintenance and well servicing activity in 2018 compared to the prior year.

Electricity generation expenses per Boe increased by 34% to $2.09 per Boe for the year ended December 31, 2018 from $1.56 per Boe in 2017, including the successor and predecessor periods. Electricity generation expenses in 2018 increased in absolute dollars by $3 million or 14% compared to the year ended December 31, 2017, including the successor and predecessor periods, due to higher fuel costs, mostly due to more volumes purchased for increased steam and electricity cogeneration. The increase on per Boe basis was largely due to the impact of lower volumes in 2018 noted above from the change in production mix resulting from the Hugoton and Hill transactions.

In 2018 we began hedging a portion of our internal consumption of natural gas used primarily to fuel our cogeneration units. Gains on natural gas derivatives in 2018 reflected relatively high gas prices in California, compared to the strike price of our derivatives.

Transportation expenses per Boe decreased by 54% to $1.00 per Boe for the year ended December 31, 2018 from $2.19 per Boe in 2017, including the successor and predecessor periods, primarily due to the Hugoton Disposition, which required significant transportation expenses. Transportation expenses in absolute dollars decreased in 2018 by $16 million or 61% when compared to the year ended December 31, 2017, including the successor and predecessor periods.

Marketing expenses, which primarily represent the cost of natural gas purchased from third parties, decreased in 2018 when compared to the year ended December 31, 2017, including the successor and predecessor periods, primarily due to lower sales volumes.

General and administrative expenses decreased in 2018 by $10 million or 16% when compared to the year ended December 31, 2017, including the successor and predecessor periods, in absolute dollars. This activity was consistent with our post-emergence efforts to build out our corporate structure in 2017 while reducing restructuring costs going forward. General and administrative expenses mainly consisted of management, support staff, legal and professional services, non-cash stock-based compensation and annual cash incentives, which are largely based upon, and fluctuate with, our financial performance. On a per Boe basis, general and administrative expenses decreased from $5.51 in 2017 to $5.48 in year ended December 31, 2018. In 2018 and 2017, general and administrative expenses included non-recurring restructuring and other costs of approximately $7 million and $30 million, respectively, and non-cash stock compensation costs of approximately $7 million and $2 million, respectively. Adjusted general and administrative expenses were $4.13 per Boe for 2018 compared to $2.74 per Boe for 2017. The increase in adjusted general and administrative expenses per Boe reflected increased costs associated with supporting the company's growth and public company status, as well as the impact of lower volumes noted above from the change in production mix resulting from the Hugoton and Hill transactions. Adjusted general and administrative expenses is a non-GAAP financial measure defined as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. Please see "—Non-GAAP Financial Measure" for a reconciliation to the GAAP financial measure of general and administrative expenses.

Depreciation, depletion and amortization decreased in 2018 by $10 million or 11% when compared to the year ended December 31, 2017, including the successor and predecessor periods. This decrease was largely driven by the decreased year-over-year production, partially offset by higher depreciation and depletion rates for 2018 due to the impact of the July 2017 Hugoton Disposition (lower rates) and Hill Acquisition (higher rates).

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)		Berry LLC (Predecessor)		
	(c) Year Ended December 31, 2018	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c)-((a)+(b)) change	% change
		(in thousands)			
Severance taxes	$ 9,373	$ 8,992	$ 1,540	$ (1,159)	(11)%
Ad valorem taxes	13,556	11,599	2,108	(151)	(1)%
Greenhouse gas allowances	10,188	13,620	1,564	(4,996)	(33)%
Total taxes other than income taxes	$ 33,117	$ 34,211	$ 5,212	$ (6,306)	(16)%

Taxes, other than income taxes per BOE decreased by 1% to $3.36 per BOE for the year ended December 31, 2018 from $3.40 per BOE in 2017, including the successor and predecessor periods. These costs decreased in 2018 by $6 million or 16% compared to 2017. The $1 million or 11% lower severance taxes in 2018 compared to 2017, including successor and predecessor periods, was largely a result of lower production, the basis for severance taxes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, were comparable year-over-year. Greenhouse gas allowances decreased in 2018 by $5 million or 33% when compared to the year ended December 31, 2017, including the successor and predecessor periods. This was a result of additional free allowances in 2018, which reduced the average unit cost of the incurred emissions compared to 2017.

Gains on Sale of Assets and Other, Net

Gains on sales of assets and other, net decreased in 2018 by $20 million or 88% compared to the year ended December 31, 2017, including the successor and predecessor periods. The gains in 2018 included a $4 million gain from the sale of our East Texas property, offset by a $1 million loss on settlement of asset retirement obligations, largely due to a change in timing of the retirements. The 2017 gains included a $23 million gain on the sale of our Hugoton assets.

Other Income (Expenses)

	Berry Corp. (Successor)		Berry LLC (Predecessor)		
	(c) Year Ended December 31, 2018	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c)-((a)+(b)) change	% change
		(in thousands)			
Interest expense	$ (35,648)	$ (18,454)	$ (8,245)	$ (8,949)	34 %
Other, net	243	4,071	(63)	(3,765)	(94)%
Total other income (expenses)	$ (35,405)	$ (14,383)	$ (8,308)	$ (12,714)	56 %

Interest expense increased in 2018 by $9 million or 34% compared to the year ended December 31, 2017, including the successor and predecessor periods, due to the interest expense on the 7% 2026 Notes issued in February 2018, partially offset by lower interest expense on the RBL Facility which had reduced borrowings in 2018 compared to 2017. Other income, net, for the year ended December 31, 2017 primarily consisted of a refund of a federal income tax overpayment from a prior year.

Reorganization Items, Net

Reorganization items, net, reflected a gain of approximately $25 million for the year ended December 31, 2018 compared to an expense of $509 million for the year ended December 31, 2017, including the successor and predecessor periods. The gains for 2018 were primarily due to a return of $23 million from the funds reserved for the claims of the general unsecured creditors, coupled with a third-party bankruptcy claim receipt and the resolution of pre-emergence liabilities, partially offset by remaining bankruptcy-related legal and professional fees. Reorganization items represent costs and income directly associated with the Chapter 11 Proceedings since May 11, 2016, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments are determined.

The following table summarizes the components of reorganization items included on the statement of operations:

	Berry Corp. (Successor)		Berry LLC (Predecessor)		
	(c) Year Ended December 31, 2018	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c)-((a)+(b)) change	% change
		(in thousands)			
Return of undistributed funds from cash distribution pool	$ 22,855	$ —	$ —	22,855	100 %
Gains on resolution of pre-emergence liabilities and claims	3,713	—	—	3,713	100 %
Legal and other professional advisory fees	(3,083)	(1,027)	(19,481)	17,425	(85)%
Gains on settlement of liabilities subject to compromise	—	—	421,774	(421,774)	(100)%
Fresh-start valuation adjustments	—	—	(920,699)	920,699	(100)%
Other	1,205	(705)	10,686	(8,776)	(88)%
Total reorganization items, net	$ 24,690	$ (1,732)	$ (507,720)	$ 534,142	(105)%

Income Tax Expense (Benefit)

Income tax expense increased in 2018 compared to 2017, including the successor and predecessor periods, by approximately $40 million due to the significant increase in pretax income in 2018 compared to the pre-tax loss in 2017 and the change in the effective tax rates. The key contributor to the change in our effective rate from (15)% in the ten months ended December 31, 2017 to 23% for the year ended December 31, 2018 was the reduction in the valuation allowance. Our earnings for 2018 allowed for the release of our valuation allowance, resulting in an effective tax rate less than the statutory federal and state tax rates.

Series A Preferred Stock dividends and conversion to common stock

The increase in Series A Preferred Stock dividends and conversion to common stock in 2018 compared to the ten months ended December 31, 2017 was due to a $60 million payment made to preferred stockholders in the Series A Preferred Stock Conversion in conjunction with our IPO, and the $27 million conversion value assigned to the additional 1.9 million shares of common stock received by the preferred stockholders.

Results of Operations - Ten Months Ended December 31, 2017, Two Months Ended February 28, 2017 and Year ended December 31, 2016

Our results of operations for the year ended December 31, 2017 are reflected in the tables and narrative discussion that follows in two distinct periods, the two months ended February 28, 2017 and the ten months ended December 31, 2017, as a result of our emergence from bankruptcy on February 28, 2017. References in these results of operations to "the change" and "the percentage change" compare the year ended December 31, 2016 results to the combined results for the comparison period in 2017 in order to provide comparability of such information. While this combined presentation is a non-GAAP presentation for which there is no comparable GAAP measure, management believes that providing this financial information is the most relevant and useful method for comparing the periods before and after the Effective Date.

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) Change	% Change
		(in thousands)			
Revenues and other:					
Oil, natural gas and NGL sales	$ 357,928	$ 74,120	$ 392,345	$ 39,703	10 %
Electricity sales	21,972	3,655	23,204	2,423	10 %
Gains (losses) on oil derivatives	(66,900)	12,886	(15,781)	(38,233)	(242)%
Marketing revenues	2,694	633	3,653	(326)	(9)%
Other revenues	3,975	1,424	7,570	(2,171)	(29)%
Total revenues and other	319,669	92,718	410,991	1,396	—%
Expenses:					
Lease operating expenses	149,599	28,238	185,056	(7,219)	(4)%
Electricity generation expenses	14,894	3,197	17,133	958	6 %
Transportation expenses	19,238	6,194	41,619	(16,187)	(39)%
Marketing expenses	2,320	653	3,100	(127)	(4)%
General and administrative expenses	56,009	7,964	79,236	(15,263)	(19)%
Depreciation, depletion and amortization	68,478	28,149	178,223	(81,596)	(46)%
Impairment of long-lived assets	—	—	1,030,588	(1,030,588)	(100)%
Taxes, other than income taxes	34,211	5,212	25,113	14,310	57 %
(Gains) losses on sale of assets and other, net	(22,930)	(183)	(109)	(23,004)	(21,105)%
Total expenses and other	321,819	79,424	1,559,959	(1,158,716)	(74)%
Other income (expenses)					
Interest expense	(18,454)	(8,245)	(61,268)	34,569	56 %
Other, net	4,071	(63)	(182)	4,190	2,302 %
Reorganization items, net	(1,732)	(507,720)	(72,662)	(436,790)	(601)%
Income (loss) before income taxes	(18,265)	(502,734)	(1,283,080)	762,081	59 %
Income tax expense (benefit)	2,803	230	116	2,917	2,514 %
Net income (loss)	(21,068)	$ (502,964)	$ (1,283,196)	$ 759,164	59 %
Series A Preferred Stock dividends and conversion to common stock	(18,248)	n/a	n/a	n/a	n/a
Net income (loss) attributable to common stockholders	$ (39,316)	n/a	n/a	n/a	n/a

Revenues and Other

Oil, natural gas and NGL sales increased in 2017, including the successor and predecessor periods, by $40 million or 10% when compared to the year ended December 31, 2016 due to an increase in realized oil and NGL prices and an increased mix of oil production compared to gas production as a result of the Hill Acquisition and Hugoton Disposition, partially offset by decreased natural gas and NGL production.

Electricity sales increased in 2017, including the successor and predecessor periods, by $2 million or 10% when compared to the year ended December 31, 2016 primarily due to higher volumes sold externally because of lower internal utilization as well as higher prices.

Losses on oil and natural gas derivatives increased in 2017, including the successor and predecessor periods, by $38 million or 242% when compared to the year ended December 31, 2016 primarily due to increased hedging activity, a portion of which was required by the RBL Facility, and improved commodity prices relative to the fixed prices of our derivative contracts.

Marketing revenues in 2017, including the successor and predecessor periods, were comparable to the year ended December 31, 2016.

Other revenues decreased in 2017, including the successor and predecessor periods, by $2 million or 29% when compared to the year ended December 31, 2016 due to a decrease in helium gas sales as a result of the Hugoton Disposition.

Expenses

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses in absolute dollars decreased in 2017, including the successor and predecessor periods, by $7 million or 4% when compared to the year ended December 31, 2016 primarily due to our production decline as a result of decreased development activity and a reduction of steamflooding. Lease operating expenses per Boe increased to $15.32 per Boe in 2017, including the successor and predecessor periods, from $12.73 per Boe for the year ended December 31, 2016. The increase in lease operating expenses per Boe was primarily due to the effect of the Hugoton Disposition (natural gas production) and the Hill Acquisition (oil production), both of which occurred in July 2017, reflecting higher operating expenses associated with oil production compared to natural gas production. While production volumes decreased as a result of the Hugoton Disposition and Hill Acquisition, which decrease adversely impacted costs per Boe, our oil, natural gas and NGL revenues remained constant due to a product mix more heavily weighted towards oil.

Electricity generation expenses increased in 2017, including the successor and predecessor periods, by $1 million or 6% when compared to the year ended December 31, 2016, primarily due to the increase in the price of natural gas used in steam generation, for which electricity generation is a by-product.

Transportation expenses decreased in 2017, including the successor and predecessor periods, by $16 million or 39% when compared to the year ended December 31, 2016, primarily due to the cancellation of uneconomic contracts in the Chapter 11 Proceedings and the Hugoton Disposition, which required significant transportation expenses.

Marketing expenses in 2017, including the successor and predecessor periods, were comparable to the year ended December 31, 2016.

General and administrative expenses decreased in 2017, including the successor and predecessor periods, by $15 million or 19% when compared to the year ended December 31, 2016 primarily due to the management change in conjunction with our emergence from bankruptcy. The reduction in absolute dollars offset by lower production resulted in higher general and administrative expenses per Boe for the year ended December 31, 2017 when compared to the same period in 2016. General and administrative expenses include non-recurring restructuring and other costs of approximately $30 million and non-cash stock compensation costs of approximately $2 million for the ten months ended December 31, 2017. General and administrative expenses in 2016 mainly consisted of allocations from our parent company at the time.

Depreciation, depletion and amortization decreased in 2017, including the successor and predecessor periods, by $82 million or 46% when compared to the year ended December 31, 2016, primarily due to the fair market revaluation of our assets in fresh-start accounting resulting in a lower depreciable asset base and lower depreciation and depletion rates. Lower production in 2017 also contributed to the reduction in absolute dollars of depreciation, depletion and amortization for the year ended December 31, 2017, including successor and predecessor periods, when compared to 2016.

Impairment of Long-Lived Assets

We recorded the following non-cash impairment charges associated with proved oil and natural gas properties:

	Berry Corp. (Successor)	Berry LLC (Predecessor)	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
		(in thousands)	
California operating area	$ —	$ —	$ 984,288
Uinta basin operating area	—	—	26,677
East Texas operating area[(1)]	—	—	6,387
Proved oil and natural gas properties	—	—	1,017,352
Unproved oil and natural gas properties	—	—	13,236
Impairment of long-lived assets	$ —	$ —	$ 1,030,588

(1) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

The impairment charge of $1.0 billion for the year ended December 31, 2016 was primarily due to a decline in commodity prices and changes in expected capital development resulting in a decline of our proved reserves.

Taxes, Other Than Income Taxes

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
		(in thousands)			
Severance taxes	$ 8,992	$ 1,540	$ 7,968	$ 2,564	32 %
Ad valorem taxes	11,599	2,108	10,951	2,756	25 %
Greenhouse gas allowances	13,620	1,564	6,063	9,121	150 %
Other	—	—	131	(131)	(100)%
Total taxes other than income taxes	$ 34,211	$ 5,212	$ 25,113	$ 14,310	57 %

Taxes, other than income taxes, increased in 2017, including the successor and predecessor periods, by $14 million or 57% compared to the year ended December 31, 2016. Severance taxes, which are a function of production in certain jurisdictions, increased in 2017, including successor and predecessor periods, by $2.5 million or 32% primarily because of increased production in those areas. Ad valorem taxes, which are based on the value of reserves and production equipment, and vary by location, increased in 2017, including the successor and predecessor periods, by $3 million or 25% compared to the year ended December 31, 2016, as a result of higher estimated valuations by various tax authorities based on increased commodity prices. Greenhouse gas allowances increased in 2017, including the successor and predecessor periods, by $9 million or 150% when compared to the year ended December 31, 2016, primarily due to increased development activity in the second half of 2017 and an increase in the price of allowances.

Gains on Sale of Assets and Other, Net

Gains on sales of assets and other, net increased in 2017, including the successor and predecessor periods, by $23 million, compared to the year ended December 31, 2016, primarily due to the Hugoton Disposition.

Other Income (Expenses)

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
		(in thousands)			
Interest expense	$ (18,454)	$ (8,245)	$ (61,268)	$ 34,569	56%
Other, net	4,071	(63)	(182)	4,190	2,302%
Total other income (expenses)	$ (14,383)	$ (8,308)	$ (61,450)	$ 38,759	63%

Interest expense decreased in 2017, including the successor and predecessor periods, by $35 million or 56% compared to the year ended December 31, 2016, due to reduced debt resulting from the bankruptcy. Other income, net, for the year ended December 31, 2017, primarily consists of a refund of a federal income tax overpayment from a prior year.

Reorganization Items, Net

Reorganization items, net, contributed a larger loss in 2017, including the successor and predecessor periods by $437 million or 600% compared to the year ended December 31, 2016, primarily due to the impact from the application of fresh-start accounting in conjunction with our emergence from bankruptcy during the two months ended February 28, 2017, partially offset by the gains on settlement of liabilities subject to compromise. Reorganization items represent costs and income directly associated with the Chapter 11 Proceedings since May 11, 2016, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments are determined.

The following table summarizes the components of reorganization items included on the statement of operations:

	Berry Corp. (Successor)	Berry LLC (Predecessor)			
	(a) Ten Months Ended December 31, 2017	(b) Two Months Ended February 28, 2017	(c) Year Ended December 31, 2016	((a)+(b))-(c) change	% change
		(in thousands)			
Gains on settlement of liabilities subject to compromise	$ —	$ 421,774	$ —	$ 421,774	—
Legal and other professional advisory fees	(1,732)	(19,481)	(30,130)	8,917	30 %
Unamortized premiums	—	—	10,923	(10,923)	(100)%
Terminated contracts	—	—	(55,148)	55,148	100 %
Fresh-start valuation adjustments	—	(920,699)	—	(920,699)	—
Other	—	10,686	1,693	8,993	531 %
Total reorganization items, net	$ (1,732)	$ (507,720)	$ (72,662)	$ (436,790)	(601)%

Income Tax Expense (Benefit)

On the Effective Date, upon consummation of the Plan, we became subject to federal and state income taxes as a C corporation. Prior to the consummation of the Plan, we were treated as a disregarded entity for federal and state income tax purposes as a limited liability company, with the exception of the State of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the State of Texas, we did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for our operations prior to the Effective Date.

Income tax expense increased in 2017, including the successor and predecessor periods, by $3 million when compared to the year ended December 31, 2016 as a result of federal and state alternative minimum tax current taxes and a valuation allowance in excess of net deferred tax assets of $1.9 million due to the impact of applying the Tax Act legislation at the end of 2017.

Liquidity and Capital Resources

Currently, we expect our primary sources of liquidity and capital resources will be Levered Free Cash Flow, and as needed, borrowings under the RBL Facility. Depending upon market conditions and other factors, we have issued and may issue additional equity and debt securities; however, we expect our operations to continue to generate positive Levered Free Cash Flow at current commodity prices allowing us to fund maintenance operations, organic growth and, opportunistic repurchases of our common stock or debt. We believe our liquidity and capital resources will be sufficient to conduct our business and operations for the next 12 months.

IPO and Preferred Stock Conversion

In July 2018, we completed the 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.

Of the approximately $110 million of net proceeds we received in the IPO, we used approximately $105 million to repay borrowings under our RBL Facility, which included $60 million we borrowed 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 issuing and 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 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.

In connection with the IPO, each of the 37.7 million shares of our Series A Preferred Stock outstanding was automatically converted to common stock in the Series A Preferred Stock Conversion. The cash payment was to be 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 aggregate. 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. The approximate $27 million value assigned to the 1.9 million shares and the $60 million cash payment for the Series A Preferred Stock Conversion reduced the income available to common stockholders by approximately $87 million.

On August 21, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock on a pro-rated basis from the date of our IPO through September 30, 2018, which resulted in a payment of $0.09 per share in October 2018. On November 7, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the fourth quarter of 2018, which was paid in January 2019. On February 28, 2019, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the first quarter of 2019.

Preferred Stock Dividends

In March 2018, our board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 new shares per outstanding share or approximately 1,825,000 shares in total. Also in March 2018, the board approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018. In May 2018, the board of directors approved a $0.15 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended June 30, 2018. The payment was made to stockholders of record as of June 7, 2018.

2026 Notes Offering

In February 2018, we issued our 7.0% 2026 Notes through our operating subsidiary, Berry LLC, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers' discount. We used the net proceeds from the issuance 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 RBL Facility

On July 31, 2017, we entered into the RBL Facility. The RBL Facility provides for a revolving loan with up to $1.5 billion of commitments, subject to a reserve borrowing base.

The RBL Facility also 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 become effective on or about each May 1 and November 1, although each of the administrative agent and Berry LLC 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 2018, we completed a borrowing base redetermination under our RBL Facility that increased our borrowing base from $400 million to $850 million and reaffirmed our elected commitment amount at $400 million. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms. As of December 31, 2018, we had approximately $7 million in letters of credit outstanding and borrowing availability of $393 million under the RBL Facility.

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 2.50% to 3.50% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.50% to 2.50% per annum, in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.50% 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 eurodollar loans.

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

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.00 to 1.00 and (ii) a Current Ratio of at least 1.00 to 1.00. The RBL Facility also contains customary restrictions. As of December 31, 2018, our Leverage Ratio and Current Ratio were 1.63:1.00 and 3.73:1.00, respectively. As of December 31, 2018, we had $393 million available for borrowing under the RBL Facility and were in compliance with the financial covenants under the RBL Facility.

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 at least 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 are required to grant mortgages, security interests and equity pledges.

Hedging

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including through fixed-price derivative contracts. For information regarding risks related to our hedging program, see "Item 1A. Risk Factors—Risks Related to Our Business and Industry". In January and February 2019, we closed a portion of our deferred premium put positions by selling offsetting put positions and terminating contracts. We also added to our natural gas swap positions we had previously hedged. As of February 28, 2019, we had hedged approximately 15.3 MBbl/d of our 2019 crude oil production at $68 per barrel.

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.

See "—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Capital Expenditures and Capital Budget" for a description of our 2018 capital expenditure budget and expected 2019 capital expenditure budget.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Net cash:				
Provided by (used in) operating activities[1]	$ 103,100	$ 107,399	$ 22,431	$ 13,197
Used in investing activities	(119,069)	(80,525)	(3,133)	(34,602)
Provided by (used in) financing activities	15,911	(43,170)	(162,668)	(1,701)
Net decrease in cash, cash equivalents and restricted cash	$ (58)	$ (16,296)	$ (143,370)	$ (23,106)

(1) The amounts provided by operating activities in 2018 were negatively impacted by a one-time $127 million payment in May 2018 for early termination on derivatives.

Operating Activities

Cash provided by operating activities was approximately $103 million for the year ended December 31, 2018 compared to cash provided by operating activities of approximately $130 million for the year ended December 31, 2017, including the successor and predecessor periods. The amounts provided by operating activities in 2018 were negatively impacted by a one-time $127 million payment made in May 2018 for early termination on derivatives in order to better align our hedge pricing with the then-prevailing market pricing. Excluding the impact of these early hedge termination payments, the increase in cash provided by operating activities in 2018 compared to 2017 reflected higher oil prices and lower operating costs slightly offset by negative working capital effects, lower oil and gas volumes and scheduled derivative cash settlements.

Cash provided by operating activities increased for the year ended December 31, 2017, including successor and predecessor periods, by approximately $117 million when compared to the same period in 2016, primarily due to the increases in the price of oil and natural gas, and decreases in operating expenses, interest expense and costs incurred in conjunction with our emergence from bankruptcy.

Investing Activities

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Capital expenditures [1]				
Development of oil and natural gas properties	$ (112,225)	$ (52,712)	$ (859)	$ (21,988)
Purchase of other property and equipment	(15,056)	(12,767)	(2,299)	(12,808)
Proceeds from sale of properties and equipment and other	8,212	234,292	25	194
Acquisition of properties	—	(249,338)	—	—
Cash used in investing activities:	$ (119,069)	$ (80,525)	$ (3,133)	$ (34,602)

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

Cash used in investing activities was approximately $119 million for the year ended December 31, 2018. The increase in cash used for investing activities for the year ended December 31, 2018 when compared to the year ended December 31, 2017 including the successor and predecessor periods, was due to the expansion of our drilling program in accordance with the 2018 capital budget. Investing activities in 2017 included the Hill Acquisition and the Hugoton Disposition.

Cash used in investing activities increased in 2017, including the successor and predecessor periods, by $49 million compared to the year ended December 31, 2016, due to the Hill Acquisition, partially offset by the Hugoton Disposition and the increase in capital expenditures. Capital expenditures increased in 2017, including the successor and predecessor periods, by $34 million or 97% compared to the year ended December 31, 2016, primarily due to development of oil and gas properties as a result of increased liquidity. Our liquidity improved significantly in 2017 due to our emergence from bankruptcy, improved commodity prices, decreased costs and entry into the RBL Facility.

Financing Activities

Cash provided by financing activities was approximately $16 million for the year ended December 31, 2018 and was due to the net proceeds of $391 million from the issuance of our 2026 Notes and $110 million from our IPO in July, offset by $379 million in payments on our RBL Facility, a $60 million payment to preferred stockholders in connection with the Series A Preferred Conversion, $20 million payments to repurchase the rights to our common stock from certain claimholders originating from the bankruptcy process, $11 million in cash dividends declared on our Series A Preferred Stock, $7 million in dividends paid on our common stock and $3 million to acquire treasury shares under our stock repurchase program. Cash used in financing activities was approximately $43 million for the ten months ended December 31, 2017 and was primarily related to repayments of the Emergence Credit Facility (as defined below) of $400 million and payments of debt issuance costs for the RBL Facility of $22 million, partially offset by borrowings under the new RBL Facility of $379 million. Cash used in financing activities was approximately $163 million for the two months ended February 28, 2017 and was primarily related to the repayments on the Pre-Emergence Credit Facility (as defined below) of $498 million, partially offset by the receipt of proceeds from the issuance of our Series A Preferred Stock of $335 million. Cash used in financing activities was approximately $2 million for the year ended December 31, 2016 and was primarily related to repayments on the Pre-Emergence Credit Facility.

Pre-Emergence Credit Facility and Emergence Credit Facility

All outstanding obligations under the Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and certain lenders, (as amended, the “Pre-Emergence Credit Facility”) were canceled and the agreements governing these obligations were terminated on the Effective Date. Also on the Effective Date, Berry LLC entered into a new credit facility with the holders of claims under the Pre-Emergence Credit Facility, as lenders, and Wells Fargo Bank, N.A, as administrative agent, providing for a new reserves-based revolving loan with up to $550 million in borrowing commitments (the “Emergence Credit Facility”). Initial borrowings under the RBL Facility were primarily incurred to repay borrowings made under the Emergence Credit Facility. All outstanding obligations under the Emergence Credit Facility were canceled, and the agreements governing these obligations were terminated on July 31, 2017.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

On May 11, 2016 our predecessor company filed the Chapter 11 Proceeding. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding. On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. 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.

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, 2018 and December 31, 2017. 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, 2018, we are not aware of material indemnity claims pending or threatened against us.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of December 31, 2018:

	Payments Due				
	Total	**2019**	**2020-2021**	**2022-2023**	**Thereafter**
			(in thousands)		
Debt obligations:					
2026 Notes	400,000	—	—	—	400,000
Interest[(1)]	199,529	28,000	56,000	56,000	59,529
Other:					
Commodity derivatives	1,385	1,385	—	—	—
Off-Balance Sheet arrangements:					
Processing and transportation contracts[(2)]	12,769	3,195	5,923	3,651	—
Operating lease obligations	2,482	1,290	637	555	—
Other[(3)]	6,000	6,000	—	—	—
Total contractual obligations	$ 622,165	$ 39,870	$ 62,560	$ 60,206	$ 459,529

(1) Represents interest on the 2026 Notes computed at 7.0% through contractual maturity in 2026.
(2) Amounts include payments which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure transportation of our natural gas production to market as well as pipeline and processing capacity.
(3) Included are obligations of approximately $6 million, which could be higher if we elect to construct, or begin construction of, the road in which case we are obligated to cover 100% of the first $9 million of construction costs plus 50% of the all construction costs above $9 million. Alternatively, we can provide long-term access to an existing road.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2017 to December 31, 2018 are discussed below.

	Berry Corp. (Successor)			
	December 31, 2018		December 31, 2017	
	(in thousands)			
Cash and cash equivalents	$	68,680	$	33,905
Accounts receivable, net	$	57,379	$	54,720
Derivative instruments - current and long-term	$	91,885	$	—
Restricted cash	$	—	$	34,833
Other current assets	$	14,367	$	14,066
Property, plant & equipment, net	$	1,442,708	$	1,387,191
Other non-current assets	$	17,244	$	21,687
Accounts payable and accrued liabilities	$	144,118	$	97,877
Derivative instruments - current and long-term	$	—	$	75,281
Liabilities subject to compromise	$	—	$	34,833
Long-term debt	$	391,786	$	379,000
Asset retirement obligation	$	89,176	$	94,509
Other non-current liabilities	$	14,902	$	3,704
Equity	$	1,006,446	$	859,310

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

The $3 million increase in accounts receivable was primarily driven by an increase in receivables for derivative settlements.

The increase in the derivative asset reflected the early termination and replacement of certain hedge contracts during 2018 to align our hedging program with higher commodity prices and the impact of mark-to-market values on our derivatives at the end of 2018 compared to the end of 2017.

Restricted cash at December 31, 2017 represented funds set aside to settle the general unsecured creditors' claims resulting from our bankruptcy process. The decrease in restricted cash, and the corresponding decrease in liabilities subject to compromise, represented the settlement of these claims, the return of undistributed funds of approximately $23 million and professional fees related to the settlement of these claims.

The $56 million increase in property, plant and equipment was largely the result of increased capital expenditures in oil and gas properties, partially offset by increased accumulated depreciation associated with such properties.

The $4 million decrease in other non-current assets was primarily driven by amortization of debt issuance costs.

The increase in accounts payable and accrued liabilities included a $19 million increase in the accruals for the increased capital spending in 2018, an $11 million increase from the new interest payment obligations on our 2026 Notes, issued in February of 2018, a $10 million increase in dividends payable, a $3 million increase in the current portion of the asset retirement obligation, and other items, partially offset by a $10 million decrease in the current portion of our greenhouse gas liability and other items.

The decrease in the derivative liability reflected the early termination and replacement of certain hedge contracts during 2018 to align our hedging program with higher commodity prices and the impact of mark-to-market values on our derivatives at the end of 2018 compared to the end of 2017.

The increase in long-term debt resulted from the issuance of our 2026 Notes in February 2018 in the principal amount of $400 million, net of deferred financing costs, which was used to pay down the $379 million balance on our RBL Facility.

The decrease in the long-term portion of the asset retirement obligation reflected a reduction in the estimated obligation for 2018 of $5 million, a reduction due to property sales of $4 million, liabilities settled during the period of $4 million and an increase to the current portion of the asset retirement obligation of $3 million. These decreases were offset by accretion expenses of $6 million and new liabilities incurred of $5 million.

The increase in other non-current liabilities primarily represented an additional greenhouse gas liability of $12 million for production during the 2018, which is due for payment more than one year from December 31, 2018.

The increase in equity reflected the receipt of IPO net proceeds of $110 million, net income of $147 million, and stock-based incentive awards of $7 million; offset by approximately $60 million of distributions to the former preferred stockholders in connection with the Series A Preferred Stock Conversion, $20 million repurchase from certain general unsecured creditors of the right to receive shares of our common stock in settlement of their claims, $17 million in common stock dividends, and $11 million in preferred stock dividends, treasury stock purchases of $4 million and shares withheld for payment of taxes on equity awards of $4 million.

Non-GAAP Financial Measures

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

Adjusted EBITDA and Adjusted Net Income (Loss) are not measures of net income (loss) and Levered Free Cash Flow is not a measure of cash flow, 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, including restructuring costs and reorganization 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 for maintenance and 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, including restructuring costs and reorganization 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. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. 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, Adjusted Net Income (Loss) 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.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 147,102	$ (21,068)	$ (502,964)	$ (1,283,196)
Add (Subtract):				
Interest expense	35,648	18,454	8,245	61,268
Income tax (benefit) expense	43,035	2,803	230	116
Depreciation, depletion, and amortization	86,271	68,478	28,149	178,223
Derivative (gains) losses	(1,735)	66,900	(12,886)	20,386
Net cash received (paid) for scheduled derivative settlements(1)	(38,482)	3,068	534	9,708
(Gains) losses on sale of assets and other	(2,747)	(22,930)	(183)	(109)
Impairment of long-lived assets	—	—	—	1,030,588
Stock compensation expense	6,750	1,851	—	—
Non-recurring restructuring and other costs	6,773	30,325	—	—
Reorganization items, net	(24,690)	1,732	507,720	72,662
Adjusted EBITDA	$ 257,924	$ 149,613	$ 28,845	$ 89,646

(1) Net cash received (paid) for scheduled derivative settlements does not include the $127 million in cash paid for early terminated derivatives.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided (used) by operating activities:				
Net cash provided by (used in) operating activities	$ 103,100	$ 107,399	$ 22,431	$ 13,197
Add (Subtract):				
Cash interest payments	19,761	14,276	8,057	57,759
Cash income tax payments	(1,901)	1,994	—	347
Cash reorganization item (receipts) payments	832	1,732	11,838	19,116
Non-recurring restructuring and other costs	6,773	30,325	—	—
Derivative early termination payment	126,949	—	—	—
Other changes in operating assets and liabilities	2,410	(6,113)	(13,323)	(876)
Other, net	—	—	(158)	103
Adjusted EBITDA	257,924	149,613	28,845	89,646
Subtract:				
Capital expenditures - accrual basis	(147,831)	(67,963)	(5,406)	(34,796)
Interest expense	(35,648)	(18,454)	(8,245)	(61,268)
Cash dividends declared[(1)]	(28,658)	(18,248)	—	—
Levered Free Cash Flow[(2)]	$ 45,787	$ 44,948	$ 15,194	$ (6,418)

(1) Cash dividends declared in 2018 include $11 million of dividends for Series A Preferred Stock for the first two quarters of 2018 and $17 million of dividends for common stock. In connection with our IPO in July 2018, all of our outstanding Series A Preferred Stock was automatically converted into common stock. Common stock dividends were $0.09 per share for the third quarter of 2018, which was pro-rated from the date of our IPO through September 30, 2018, and $0.12 per share for the fourth quarter of 2018.

(2) Levered Free Cash Flow includes cash paid for scheduled derivative settlements of $38 million for the year ended December 31, 2018 and cash received for scheduled derivative settlements of $3 million for the ten months ended December 31, 2017, $1 million for the two months ended February 28, 2017, and $10 million for the year ended December 31, 2016.

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).

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Adjusted Net Income (Loss) reconciliation to Net income (loss)				
Net income (loss)	$ 147,102	$ (21,068)	$ (502,964)	$ (1,283,196)
Add (Subtract):				
(Gains) losses on oil and natural gas derivatives	(1,735)	66,900	(12,886)	20,386
Net cash received (paid) for scheduled derivative settlements	(38,482)	3,068	534	9,708
(Gains) losses on sale of assets and other, net	(2,747)	(22,930)	(183)	(109)
Impairments	—	—	—	1,030,588
Non-recurring restructuring and other costs	6,773	30,325	—	—
Reorganization items, net	(24,690)	1,732	507,720	72,662
Total additions (subtractions), net	(60,881)	79,095	495,185	1,133,235
Income tax benefit (expense) of adjustments at effective tax rate[(1)]	13,780	(22,147)	—	—
Adjusted Net Income (Loss)	$ 100,001	$ 35,880	$ (7,779)	$ (149,961)

(1) For the ten months ended December 31, 2017, our effective tax rate was (15%) due to a net loss and valuation allowances. For purposes of this calculation, we used the statutory rate for this period, which was 28%.

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.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:				
General and administrative expenses	$ 54,026	$ 56,009	$ 7,964	$ 79,236
Subtract:				
Non-recurring restructuring and other costs	(6,773)	(30,325)	—	—
Non-cash stock compensation expense	(6,585)	(1,819)	—	—
Adjusted General and Administrative Expenses	$ 40,668	$ 23,865	$ 7,964	$ 79,236

Off-Balance Sheet Arrangements

See "—Liquidity and Capital Resources—Lawsuits, Claims, 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.

Fresh-Start Accounting

Upon our emergence from Chapter 11 bankruptcy, we adopted fresh-start accounting which resulted in our becoming a new entity for financial reporting purposes. We were required to adopt fresh-start accounting upon our emergence from Chapter 11 bankruptcy because (i) the holders of existing voting ownership interests of Berry LLC received less than 50% of the voting shares of Berry Corp. and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims, as shown below:

		(in thousands)
Liabilities subject to compromise	$	1,000,336
Pre-petition debt not classified as subject to compromise		891,259
Post-petition liabilities		245,702
Total post-petition liabilities and allowed claims		2,137,297
Reorganization value of assets immediately prior to implementation of the Plan		(1,722,585)
Excess post-petition liabilities and allowed claims	$	414,712

Upon adoption of fresh-start accounting, the reorganization value derived from the enterprise value was allocated to our assets and liabilities based on their fair values in accordance with GAAP. The Effective Date fair values of our assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in the financial statements as of February 28, 2017, and the related adjustments thereto were recorded on the statement of operations for the two months ended February 28, 2017.

As a result of the adoption of fresh-start accounting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to February 28, 2017 are not comparable to our financial statements prior to February 28, 2017.

Our consolidated financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. 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.

Reorganization Value

Under GAAP, Berry Corp. determined a value to be assigned to the equity of the emerging entity as of the date of adoption of fresh-start accounting. The Plan and disclosure statement approved by the Bankruptcy Court did not include an enterprise value or reorganization value, nor did the Bankruptcy Court approve a value as part of its confirmation of the Plan. Our reorganization value was derived from an estimate of enterprise value, or the fair value of our long-term debt, stockholders' equity and working capital. Reorganization value approximates the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Based on the various estimates and assumptions necessary for fresh-start accounting, we estimated our enterprise value as of the Effective Date to be approximately $1.3 billion. The enterprise value was estimated using a sum of parts approach. The sum of parts approach represents the summation of the indicated fair value of the component assets of the Company. The fair value of our assets was estimated by relying on a combination of the income, market and cost approaches.

The estimated enterprise value, reorganization value and equity value are highly dependent on the achievement of the financial results contemplated in our underlying projections. While we believe the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. Additionally, the assumptions used in estimating these values are inherently uncertain and require judgment. The primary assumptions for which there is a reasonable possibility of the occurrence of a variation that would have significantly affected the reorganization value include those regarding pricing, discount rates and the amount and timing of capital expenditures.

Our principal assets are our oil and natural gas properties. The fair values of oil and natural gas properties were estimated using a valuation technique consistent with the income approach, specifically the discounted cash flows method. We also used the market approach to corroborate the valuation results from the income approach. We used a market-based weighted-average cost of capital discount rate of 10% for proved and unproved reserves, with further risk adjustment factors applied to the discounted values. The underlying commodity prices embedded in our estimated cash flows are based on the ICE (Brent) and NYMEX (Henry Hub) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that we believe will impact realizable prices. Forward curve pricing was used for years 2017 through 2019 and then was escalated at approximately 2.0%.

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date:

	(in thousands)
Enterprise value	$ 1,278,527
Plus: Fair value of non-debt liabilities	282,511
Reorganization value of the successor's assets	$ 1,561,038

The fair value of non-debt liabilities consists of liabilities assumed by Berry Corp. on the Effective Date and excludes the fair value of long-term debt.

Consolidated Balance Sheet

The adjustments included in the fresh-start consolidated balance sheet in the accompanying financial statements reflect the effects of the transactions contemplated by the Plan and executed on the Effective Date as well as fair value and other required accounting adjustments resulting from the adoption of fresh-start accounting. The explanatory notes provide additional information with regard to the adjustments recorded, methods used to determine the fair values and significant assumptions.

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. 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, net of salvage, 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 and exploratory well costs in 2018, 2017 and 2016 was not significant. 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 and are the most sensitive estimates that we make and the most likely to change. 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.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2016, we recorded non-cash impairment charges of approximately $1.0 billion associated with proved oil and natural gas properties. The 2016 impairment charges were due to a decline in commodity prices, changes in expected capital development and a decline in our estimates of proved reserves. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement (see Note 1 for definition). The impairment charges were included in “impairment of long-lived assets” on our statements of operations.

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2018 and 2017, the net capitalized costs attributable to unproved properties were approximately $388 million and $517 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, 2018.

Based on the analysis described above, for the year ended December 31, 2016, we recorded non-cash impairment charges of approximately $13 million associated with unproved oil and natural gas properties. The impairment charges in 2016 were primarily due to a decline in commodity prices and changes in expected capital development. The carrying values of the impaired unproved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in “impairment of long-lived assets” on our statements of operations.

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.

In certain cases, we do not know or cannot estimate when we may settle these obligations and therefore we cannot reasonably estimate the fair value of the liabilities. We will recognize these AROs in the periods in which sufficient information becomes available to reasonably estimate their fair values.

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 natural gas 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. We classify these measurements as Level 2.

Stock-based Compensation

Subsequent to February 28, 2017, we 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, 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.

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 in this document 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, maintenance capital requirements, 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".

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

- volatility of oil, natural gas and NGL prices;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and meet working capital requirements;
- price and availability of natural gas;

- our ability to use derivative instruments to manage commodity price risk;
- impact of environmental, health and safety, and other governmental regulations, and of current, pending, or future legislation;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our inability to replace our reserves through exploration and development activities;
- our ability to obtain permits and otherwise to meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- changes in tax laws;
- effects of competition;
- 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;
- our ability to improve our financial results and profitability following our emergence from bankruptcy and other risks and uncertainties related to our emergence from bankruptcy;
- impact of derivatives legislation affecting our ability to hedge;
- ineffectiveness of internal controls;
- concerns about climate change and other air quality issues;
- catastrophic events;
- litigation;
- our ability to retain key members of our senior management and key technical employees; and
- information technology failures or cyber attacks.

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 and cash flows are likewise affected. In addition, a non-cash write-down of our oil and gas properties may be required if commodity prices experience a 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 it is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, 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. Currently, our hedging program mainly consists of swaps and puts.

We determine the fair value of our oil and natural gas 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, 2018, the fair value of our hedge positions was a net asset of approximately $92 million. A 10% increase in the oil and natural gas index prices above the December 31, 2018 prices would result in a net liability of approximately $82 million, which represents a decrease in the fair value of our derivative position of approximately $10 million; conversely, a 10% decrease in the oil and natural gas index prices below the December 31, 2018 prices would result in a net asset of approximately $102 million, which represents an increase in the fair value of approximately $10 million. For additional information about derivative activity, see Note 6 to our consolidated financial statements.

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.

Counterparty 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. 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, 2018 and five at December 31, 2017. 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, 2018 was not material and losses associated with credit risk have been insignificant for all periods presented.

Interest Rate Risk

Our RBL Facility has a variable interest rate on outstanding balances. We used a portion of the proceeds from the issuance of the 2026 Notes to repay borrowings under the RBL Facility in February 2018. As of December 31, 2018, there were no borrowings under our RBL Facility and thus we were not exposed to interest rate risk on this facility. The 2026 Notes have a fixed interest rate and thus we are not exposed to interest rate risk on these instruments. See Note 5 to our consolidated financial statements for additional information regarding interest rates on outstanding debt.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders and Board of Directors
Berry Petroleum Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Berry Petroleum Corporation and its subsidiary (the "Company") as of December 31, 2018 (Successor) and December 31, 2017 (Successor), the related consolidated statements of operations, equity, and cash flows for the year ended December 31, 2018 (Successor), the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 (Predecessor), and the year ended December 31, 2016 (Predecessor), 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, 2018 (Successor) and December 31, 2017 (Successor) and the results of its operations and its cash flows for the year ended December 31, 2018 (Successor), the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 (Predecessor), and the year ended December 31, 2016 (Predecessor), in conformity with U.S. generally accepted accounting principles.

Basis of Presentation

As discussed in Note 2 to the consolidated financial statements, the Company emerged from bankruptcy on February 28, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification Subtopic 852-10, *Reorganizations*, for the Successor as a new entity with assets, liabilities, and a capital structure having carrying amounts not comparable with prior periods as described in Note 2.

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 auditing 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. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2013.
Los Angeles, California
March 7, 2019

BERRY PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 68,680	$ 33,905
Accounts receivable, net of allowance for doubtful accounts of $950 at December 31, 2018 and $970 at December 31, 2017	57,379	54,720
Derivative instruments	88,596	—
Restricted cash	—	34,833
Other current assets	14,367	14,066
Total current assets	229,022	137,524
Non-current assets:		
Oil and natural gas properties	1,461,993	1,342,453
Accumulated depletion and amortization	(123,217)	(54,785)
Total oil and natural gas properties, net	1,338,776	1,287,668
Other property and equipment	119,710	104,879
Accumulated depreciation	(15,778)	(5,356)
Total other property and equipment, net	103,932	99,523
Derivative instruments	3,289	—
Other non-current assets	17,244	21,687
Total assets	$ 1,692,263	$ 1,546,402
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 144,118	$ 97,877
Derivative instruments	—	49,949
Liabilities subject to compromise	—	34,833
Total current liabilities	144,118	182,659
Non-current liabilities:		
Long term debt	391,786	379,000
Derivative instruments	—	25,332
Deferred income taxes	45,835	1,888
Asset retirement obligation	89,176	94,509
Other non-current liabilities	14,902	3,704
Commitments and Contingencies - Note 7		
Equity:		
Series A Preferred Stock ($.001 par value; 250,000,000 shares authorized; none outstanding at December 31, 2018 and 35,845,001 shares outstanding at December 31, 2017)	—	335,000
Common stock ($.001 par value; 750,000,000 shares authorized; 81,651,098 and 32,920,000 shares issued; and 81,202,437 and 32,920,000 shares outstanding, at December 31, 2018 and December 31, 2017, respectively)	82	33
Additional paid-in capital	914,540	545,345
Treasury stock, at cost (448,661 shares at December 31, 2018 and none at December 31, 2017)	(24,218)	—
Retained earnings (accumulated deficit)	116,042	(21,068)
Total equity	1,006,446	859,310
Total liabilities and equity	$ 1,692,263	$ 1,546,402

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

BERRY PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	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)			
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$ 552,874	$ 357,928	$ 74,120	$ 392,345
Electricity sales	35,208	21,972	3,655	23,204
Gains (losses) on oil derivatives	(4,621)	(66,900)	12,886	(15,781)
Marketing revenues	2,322	2,694	633	3,653
Other revenues	774	3,975	1,424	7,570
Total revenues and other	586,557	319,669	92,718	410,991
Expenses and other:				
Lease operating expenses	188,776	149,599	28,238	185,056
Electricity generation expenses	20,619	14,894	3,197	17,133
Transportation expenses	9,860	19,238	6,194	41,619
Marketing expenses	2,140	2,320	653	3,100
General and administrative expenses	54,026	56,009	7,964	79,236
Depreciation, depletion and amortization	86,271	68,478	28,149	178,223
Impairment of long-lived assets	—	—	—	1,030,588
Taxes, other than income taxes	33,117	34,211	5,212	25,113
(Gains) losses on natural gas derivatives	(6,357)	—	—	—
(Gains) losses on sale of assets and other, net	(2,747)	(22,930)	(183)	(109)
Total expenses and other	385,705	321,819	79,424	1,559,959
Other income (expenses):				
Interest expense	(35,648)	(18,454)	(8,245)	(61,268)
Other, net	243	4,071	(63)	(182)
Total other income (expenses)	(35,405)	(14,383)	(8,308)	(61,450)
Reorganization items, net	24,690	(1,732)	(507,720)	(72,662)
Income (loss) before income taxes	190,137	(18,265)	(502,734)	(1,283,080)
Income tax expense (benefit)	43,035	2,803	230	116
Net income (loss)	147,102	(21,068)	$ (502,964)	$ (1,283,196)
Series A Preferred Stock dividends and conversion to common stock	(97,942)	(18,248)	n/a	n/a
Net income (loss) attributable to common stockholders	$ 49,160	$ (39,316)	n/a	n/a
Income (loss) per share attributable to common stockholders:				
Basic	$ 0.85	$ (1.02)	n/a	n/a
Diluted	$ 0.85	$ (1.02)	n/a	n/a

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

BERRY PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Berry LLC (Predecessor)		
	Member's Capital	Retained Earnings (Accumulated Deficit)	Total Member's Equity
	(in thousands)		
December 31, 2015	$ 2,798,713	$ (1,012,554)	$ 1,786,159
Net loss	—	(1,283,196)	(1,283,196)
December 31, 2016	2,798,713	(2,295,750)	502,963
Net loss	—	(502,964)	(502,964)
Other	1	—	1
Balance before cancellation of Predecessor Equity	2,798,714	(2,798,714)	—
Cancellation of Predecessor Equity	(2,798,714)	2,798,714	—
Predecessor February 28, 2017	$ —	$ —	$ —

	Berry Corp. (Successor)					
	Series A Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Equity
	(in thousands)					
Issuance of Series A convertible preferred stock	$ 335,000	$ —	$ —	$ —	$ —	$ 335,000
Issuance of Common Stock	—	33	543,494	—	—	543,527
Successor February 28, 2017	335,000	33	543,494	—	—	878,527
Net loss	—	—	—	—	(21,068)	(21,068)
Stock based compensation	—	—	1,851	—	—	1,851
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 (loss)	—	—	—	—	147,102	147,102
December 31, 2018	$ —	$ 82	$ 914,540	$ (24,218)	$ 116,042	$1,006,446

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

BERRY PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Cash flow from operating activities:				
Net income (loss)	$ 147,102	$ (21,068)	$ (502,964)	$ (1,283,196)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	86,271	68,478	28,149	178,223
Amortization of debt issuance costs	5,430	1,988	416	1,849
Impairment of long-lived asset	—	—	—	1,030,588
Stock-based compensation expense	6,750	1,851	—	—
Deferred income taxes	43,946	1,888	9	(11)
(Decrease) increase in allowance for doubtful accounts	(20)	970	—	—
(Gains) losses on sale of assets and other, net	(2,747)	(22,930)	(25)	(212)
Reorganization expenses, net - non-cash	(25,523)	—	501,872	43,289
Derivatives activities:				
Total (gains) losses	(1,735)	66,900	(12,886)	20,386
Cash settlements on normal derivatives	(38,482)	3,068	534	8,007
Cash payments on early-terminated derivatives	(126,949)	—	—	1,701
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable	(1,683)	(7,022)	(9,152)	(6,556)
(Increase) decrease in other assets	(3,190)	(13,175)	(2,842)	1,962
Increase (decrease) in accounts payable and accrued expenses	19,526	6,619	18,330	22,101
(Decrease) increase in other liabilities	(5,596)	19,832	990	(4,934)
Net cash provided by (used in) operating activities	103,100	107,399	22,431	13,197
Cash flow from investing activities:				
Capital expenditures:				
Development of oil and natural gas properties	(112,225)	(52,712)	(859)	(21,988)
Purchases of other property and equipment	(15,056)	(12,767)	(2,299)	(12,808)
Acquisition of properties	—	(249,338)	—	—
Proceeds from sale of properties and equipment and other	8,212	234,292	25	194
Net cash provided by (used in) investing activities	(119,069)	(80,525)	(3,133)	(34,602)
Cash flow from financing activities:				
Repayments on new credit facility	(582,510)	(23,285)	—	—
Borrowings under new credit facility	203,510	402,285	—	—
IPO proceeds net of issuance costs	133,805	—	—	—
Repurchase of common stock	(23,712)	—	—	—
Payment to preferred stockholders in conversion	(60,273)	—	—	—
Issuance of 2026 Senior Unsecured Notes	400,000	—	—	—
Dividends paid on Series A Preferred Stock	(11,301)	—	—	—
Dividends paid on common stock	(7,365)	—	—	—
Purchase of treasury stock	(23,351)	—	—	—
Shares withheld for payment of taxes on equity awards	(3,699)	—	—	—
Debt issuance costs	(9,193)	(22,170)	—	—
Borrowings on emergence credit facility	—	51,000	—	—
Repayments on emergence credit facility	—	(451,000)	—	—
Proceeds from sale of Series A Preferred Stock	—	—	335,000	—
Repayments on pre-emergence credit facility	—	—	(497,668)	(1,701)
Net cash provided by (used in) financing activities	15,911	(43,170)	(162,668)	(1,701)
Net (decrease) increase in cash and cash equivalents	(58)	(16,296)	(143,370)	(23,106)
Cash, cash equivalents and restricted cash:				
Beginning	68,738	85,034	228,404	251,510
Ending	$ 68,680	$ 68,738	$ 85,034	$ 228,404

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

Note 1—Basis of Presentation and Significant Accounting Policies

"Berry Corp." refers to Berry Petroleum Corporation, a Delaware corporation which, on and after February 28, 2017 is the sole member of Berry Petroleum Company, LLC.

"Berry LLC" refers to Berry Petroleum Company, LLC, a Delaware limited liability company.

As the context may require, the "Company", "we", "our" or similar words refer to (i) Berry Corp. (the "Successor") and Berry LLC, its consolidated subsidiary, as of and after February 28, 2017, as a whole or (ii) either Berry Corp. or Berry LLC on an individual basis as of and after February 28, 2017. References to historical activities of the "Company" prior to February 28, 2017, refer to activities of Berry LLC (the "Predecessor").

"Linn Energy" refers to Linn Energy, LLC, a Delaware limited liability company of which Berry LLC was formerly a wholly-owned, indirect subsidiary and LinnCo, LLC ("LinnCo" and, together with Linn Energy, the "Linn Entities"), until February 28, 2017.

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located 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).

In July, we completed the initial public offering (the "IPO") of our common stock and as a result, on July 26, 2018, our common stock began trading on the Nasdaq Global Select Market ("NASDAQ") under the ticker symbol BRY.

As discussed further in Note 2, on May 11, 2016 (the "Petition Date"), the Linn entities and, consequently, Berry LLC, filed voluntary petitions for relief under Chapter 11 ("Chapter 11") of the U.S. Bankruptcy Code. Berry LLC emerged from bankruptcy as a stand-alone company separate from Linn Energy effective February 28, 2017 (the "Effective Date").

Principles of Consolidation and Reporting

The consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("GAAP") and include the accounts of the Successor and its wholly owned subsidiary after February 28, 2017 and the accounts of the Predecessor prior to February 28, 2017. All significant intercompany transactions and balances have been eliminated 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.

Bankruptcy Accounting

The consolidated financial statements have been prepared as if the Company will continue as a going concern and reflect the application of GAAP. 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. In addition, pre-petition unsecured and under-secured obligations that may be impacted by the bankruptcy reorganization process have been classified as "liabilities subject to compromise" on our balance sheet. These liabilities are reported at the amounts allowed as claims by the Bankruptcy Court, although they may be settled for less.

Upon emergence from bankruptcy on February 28, 2017, we adopted fresh-start accounting which resulted in Berry Corp. becoming the financial reporting entity. As a result of the application of fresh-start accounting and the effects of the implementation of the Plan (see Note 2 for definition), the financial statements on or after February 28, 2017 are not comparable to the financial statements prior to that date. See Note 3 for additional information.

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 and fair values of assets acquired and liabilities assumed. In addition, as part of fresh-start accounting, we made estimates and assumptions related to our reorganization value, liabilities subject to compromise and the fair value of assets and liabilities recorded.

As fair value is a market-based measurement, it was determined based on the assumptions that we believe market participants would use. We based these assumptions on management's best estimates and judgment. Management evaluates its assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, that management believes to be reasonable under the circumstances. Such assumptions are adjusted when management determines that facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates.

Cash Equivalents

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

Restricted Cash

As of December 31, 2018 and December 31, 2017, “restricted cash” was approximately zero and $35 million, respectively. Restricted cash was classified as a current asset on the consolidated balance sheets and represents cash that was used to settle certain claims and pay certain professional fees in accordance with the Plan (as defined below).

Inventories

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

Oil and Natural Gas Properties

Proved Properties

We account for oil and natural gas properties in accordance with the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. 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, net of salvage, 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 and exploratory well costs in 2018, 2017 and 2016 was not significant. 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 are reduced to fair value when the expected undiscounted future cash flows are less than net book value. We measure the fair values of proved properties are measured 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 and are the most sensitive estimates we make and the most likely to change. 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.

Impairment of Proved Properties

Based on the analysis described above, for the year ended December 31, 2016, we recorded non-cash impairment charges of approximately $1.0 billion associated with proved oil and natural gas properties. The 2016 impairment charges were due to a decline in commodity prices, changes in expected capital development and a decline in our estimates of proved reserves. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges were included in “impairment of long-lived assets” on our statements of operations.

The 2016 non-cash impairment charges associated with proved oil and natural gas properties arose in the following operating areas of our Predecessor:

	Berry LLC (Predecessor) Year Ended December 31, 2016
	(in thousands)
California operating area	$ 984,288
Uinta basin operating area	26,677
East Texas operating area	6,387
Total non-cash impairment charges	$ 1,017,352

Unproved Properties

A portion of the carrying value of our oil and gas properties was attributable to unproved properties. At December 31, 2018 and 2017, the net capitalized costs attributable to unproved properties were approximately $388 million and $517 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, 2018.

Based on the analysis described above, for the year ended December 31, 2016, we recorded non-cash impairment charges of approximately $13 million associated with unproved oil and natural gas properties. The impairment charges in 2016 were primarily due to a decline in commodity prices and changes in expected capital development. The carrying values of the impaired unproved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in "impairment of long-lived assets" on our statements of operations.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, buildings, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These assets are recorded at cost and are depreciated using the straight-line method based on expected useful lives ranging from 5 to 39 years for buildings and leasehold improvements and two to 30 years for plant and pipeline, drilling and other equipment.

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 $89 million, $95 million and $109 million were included in long term liabilities as of December 31, 2018, December 31, 2017, and February 28, 2017, respectively, with the remaining current portion included in accrued liabilities:

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
		(in thousands)	
Beginning balance	$ 97,422	$ 113,275	$ 141,798
Liabilities incurred	4,901	—	152
Settlements and payments	(3,555)	(2,333)	(861)
Accretion expense	6,258	5,562	1,112
Reduction due to property sales	(4,145)	(19,082)	—
Revisions	(5,333)	—	—
Fresh-Start adjustment	—	—	(28,926)
Ending balance	$ 95,548	$ 97,422	$ 113,275

Revenue Recognition

We recognize revenue from oil, natural gas and natural gas liquids ("NGLs") when title has passed from us to the purchaser, and in the case of electricity when it is delivered to a custody transfer point, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. We recognize our share of oil, natural gas and NGL revenues net of any royalties and other third-party share. The electricity and natural gas we produce and use in our operations are not included in revenues. The excess electricity produced by our cogeneration facilities is marketed to third parties under multi-year contracts approved by the California Public Utilities Commission (the "CPUC") for which the electricity is offered daily into the California electric market to be dispatched based on pricing and grid requirements. In addition, we engage in the purchase, gathering and transportation of third-party natural gas and subsequently market such natural gas to independent purchasers under separate arrangements. As a result, we separately report third-party marketing revenues and marketing expenses.

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 natural gas 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. 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.

Stock-based Compensation

Subsequent to February 28, 2017, we 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, 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 five 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

Prior to the consummation of the Plan, as defined below, the Predecessor was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the company are passed through to its members. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, the Predecessor was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of the company.

On the Effective Date, upon consummation of the Plan, the Successor became a C Corporation subject to federal and state income taxes. The impact of changes in tax regulation are reflected when enacted. 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. Restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights at the same rate as common stock.

Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income attributable to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses. For basic EPS, the weighted-average number of common shares outstanding excludes outstanding shares related to unvested restricted stock awards. For diluted EPS, the basic shares outstanding are adjusted by adding potentially dilutive securities, unless their effect is anti-dilutive.

Business and Credit Concentrations

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

We 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, 2018, our three largest customers represented approximately 35%, 28% and 13% of our sales. For the ten months ended December 31, 2017, our three largest customers represented approximately 36%, 29% and 13% of our sales. For the two months ended February 28, 2017, our two largest customers represented approximately 34% and 29% of our sales. For the year ended December 31, 2016, our two largest customers represented approximately 34% and 28% of our sales.

At December 31, 2018, trade accounts receivable from three customers represented approximately 26%, 22%, and 10% of our receivables. At December 31, 2017, trade accounts receivable from two customers represented approximately 35% and 26% of our receivables.

Recently Adopted Accounting Standards

In November 2016, the Financial Accounting Standards Board (the “FASB”) issued rules intended to address the diversity in practice in classification and presentation of changes in restricted cash on the statement of cash flows. We adopted these rules retrospectively on January 1, 2018, as a result of which we included restricted cash amounts in our beginning and ending cash balances on the statement of cash flows and included a disclosure reconciling cash and cash equivalents presented on the balance sheets to cash, cash equivalents and restricted cash on the statement of cash flows.

In March 2016, the FASB issued rules to improve the accounting for share-based payment transactions. We early-adopted these rules retrospectively on April 1, 2018 and as a result are reporting cash paid to tax authorities when we withhold shares from an employee's award as a cash outflow for financing activities on the statement of cash flows. There was no change to the other financial statements as a result of adopting these rules.

New Accounting Standards Issued, But Not Yet Adopted

In August 2017, the FASB released targeted improvements to hedge accounting standards that will expand hedge accounting for non-financial and financial risk components and amend measurement methodologies to more closely align hedge accounting with a company’s risk management activities. These rules are also intended to decrease the cost and complexity of hedge accounting. The new rules are effective for fiscal years beginning after December 15, 2018. We do not anticipate the adoption of this new rule to have a material impact on our consolidated financial statements.

In June 2016, the FASB issued rules that change how entities will measure credit losses for certain financial assets and other instruments that are not measured at fair value. These rules are effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact of these rules on our consolidated financial statements.

In February 2016, the 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-Securities Exchange Commission (“SEC”) issuers which is for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and do not expect a material impact on our consolidated results of operations.

During 2016, the FASB issued rules clarifying the new revenue recognition standard issued in 2014. The new rules are intended to improve and converge the financial reporting requirements for revenue from contracts with customers. We are an emerging growth company and have elected to delay adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 31, 2018. As such, we will adopt these rules in the first quarter of 2019 and apply the modified retrospective approach, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. We have performed an analysis of existing contracts and do not expect adoption to have a material impact on our consolidated financial statements, however, certain immaterial costs currently netted in revenue will likely be recorded in expenses. In addition, we have evaluated the expected changes to relevant business practices, accounting policies and control activities and do not expect to have a material change as a result of the adoption of these rules.

Note 2—Emergence from Voluntary Reorganization under Chapter 11

On May 11, 2016 our predecessor company filed bankruptcy. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16–60040 (the "Chapter 11 Proceeding"). On January 27, 2017, the Bankruptcy Court approved and confirmed our plan of reorganization in the Chapter 11 Proceeding (the "Plan"). On February 28, 2017 (the "Effective Date"), the Plan became effective and was implemented. 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.

Plan of Reorganization

On the Effective Date, the Company consummated the following reorganization transactions in accordance with the Plan:

- Linn Acquisition Company, LLC transferred 100% of the outstanding membership interests in Berry LLC to Berry Corp. pursuant to an assignment agreement, dated February 28, 2017 between Linn Acquisition Company, LLC and Berry Corp. (the "Assignment Agreement"). Under the Assignment Agreement, Berry LLC became a wholly-owned operating subsidiary of Berry Corp.
- The holders of claims under the Company's Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and certain lenders, (as amended, the "Pre-Emergence Credit Facility"), received (i) their pro-rated share of a cash paydown and (ii) pro-rated participation in the new facility (the "Emergence Credit Facility"). As a result, all outstanding obligations under the Pre-Emergence Credit Facility were canceled and the agreements governing these obligations were terminated.
- Berry LLC, as borrower, entered into the Emergence Credit Facility with the holders of claims under the Pre-Emergence Credit Facility, as lenders, and Wells Fargo Bank, N.A, as administrative agent, providing for a new reserves-based revolving loan with up to $550 million in borrowing commitments. For additional information about the Emergence Credit Facility, see Note 5.
- The holders of Berry LLC's 6.75% senior notes due 2020, issued by Berry LLC pursuant to a Second Supplemental Indenture, dated November 1, 2010, and 6.375% senior notes due 2022, issued by Berry LLC pursuant to a Third Supplemental Indenture, dated March 9, 2012 (collectively, the "Unsecured Notes"), received a right to their pro-rated share of either (i) 32,920,000 shares of common stock in Berry Corp. or, for those non-accredited investors holding the Unsecured Notes that irrevocably elected to receive a cash recovery, cash distributions from a $35 million cash distribution pool (the "Cash Distribution Pool") and (ii) specified rights to participate in a two-tranche offering of rights to purchase Series A Preferred Stock at an aggregate purchase price of $335 million (as further defined in the Plan, the "Berry Rights Offerings"). As a result, all outstanding obligations under the Unsecured Notes were canceled and the indentures and related agreements governing these obligations were terminated.
- 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. 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.
- Berry LLC settled all intercompany claims against Linn Energy 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 Linn Energy which Berry LLC has fully-reserved.

Bank RSA

Prior to the Petition Date, on May 10, 2016, the Debtors entered into a restructuring support agreement (the "Bank RSA") with certain holders (the "Consenting Bank Creditors"). The Bank RSA set forth, subject to certain conditions, the commitment of the Consenting Bank Creditors to support a comprehensive restructuring of the Debtors' long-term debt. The Bank RSA required the Debtors and the Consenting Bank Creditors to, among other things, support and not interfere with consummation of the restructuring transactions contemplated by the Bank RSA and, as to the Consenting Bank Creditors, vote their claims in favor of the Plan.

Liabilities Subject to Compromise

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. The Debtors have settled, and may continue to settle, claims through the Bankruptcy Court. To the extent that such adjustments relate to Unsecured Claims, no additional liability to the Company is anticipated as such claimants received only 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. 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. The liability for the cash distribution pool was $34.8 million at December 31, 2017 and is included in liabilities subject to compromise. We settled all liabilties 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

We have incurred expenses associated with the reorganization. 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:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(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	(3,083)	(1,027)	(19,481)	(30,130)
Gains on settlement of liabilities subject to compromise	—	—	421,774	—
Fresh-start valuation adjustments	—	—	(920,699)	—
Unamortized premiums	—	—	—	10,923
Terminated contracts	—	—	—	(55,148)
Other	1,205	(705)	10,686	1,693
Reorganization items, net	$ 24,690	$ (1,732)	$ (507,720)	$ (72,662)

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

Effect of Filing on Creditors

Subject to certain exceptions, under the Bankruptcy Code, the filing of Bankruptcy Petitions automatically enjoined, or stayed, the continuation of most judicial or administrative proceedings or filing of other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the Petition Date. Absent an order of the Bankruptcy Court, substantially all of the Debtors' pre-petition liabilities were subject to settlement under the Bankruptcy Code.

Although the filing of Bankruptcy Petitions triggered defaults on the Debtors' debt obligations, creditors were stayed from taking any actions against the Debtors as a result of such defaults, subject to certain limited exceptions permitted by the Bankruptcy Code. The Predecessor did not record interest expense on its senior notes for the period from May 12, 2016 through December 31, 2016 and from January 1, 2017 through February 28, 2017. For those periods, unrecorded contractual interest was approximately $35 million and $9 million, respectively.

Covenant Violations

The Predecessor's filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under its Pre-Emergence Credit Facility and its senior notes. Additionally, other events of default, including cross-defaults, occurred, including the failure to make interest payments on the Predecessor's senior notes. Under the Bankruptcy Code, the creditors under these debt agreements were stayed from taking any action against the Predecessor as a result of any default. See Note 5 for additional details about the Predecessor's debt.

Prior Credit Facility

The Pre-Emergence Credit Facility contained a requirement to deliver audited financial statements without a going concern or like qualification or exception. Consequently, the filing of the Predecessor's 2015 Annual Report on Form 10-K which included a going concern explanatory paragraph resulted in a default under the Pre-Emergence Credit Facility as of the filing date, March 28, 2016, subject to a 30-day grace period.

On April 12, 2016, the Predecessor entered into an amendment to the Pre-Emergence Credit Facility. The amendment provided for, among other things, an agreement that (i) certain events would not become defaults or events of default until May 11, 2016, (ii) the borrowing base would remain constant until May 11, 2016, unless reduced as a result of swap agreement terminations or collateral sales, (iii) the Predecessor would have access to $45 million in cash that was previously restricted in order to fund ordinary course operations and (iv) the Predecessor, the administrative agent and the lenders would negotiate in good faith the terms of a restructuring support agreement in furtherance of a restructuring of the capital structure of the Predecessor. As a condition to closing the amendment, the Predecessor provided control agreements over certain deposit accounts.

The filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under the Pre-Emergence Credit Facility. However, under the Bankruptcy Code, the creditors under this debt agreement were stayed from taking any action against the Predecessor as a result of the default.

Senior Notes

The Predecessor deferred making an interest payment totaling approximately $18 million due March 15, 2016, on the Predecessor's 6.375% senior notes due September 2022, which resulted in the Predecessor being in default under these senior notes. The indenture governing the notes provided the Predecessor a 30-day grace period to make the interest payment.

On April 14, 2016, within the 30-day interest payment grace period provided for in the indenture governing the notes, the Predecessor made an interest payment of approximately $18 million in satisfaction of its obligations.

The Predecessor failed to make interest payments due on its senior notes subsequent to April 14, 2016.

The filing of the Bankruptcy Petitions constituted an event of default that accelerated the Predecessor's obligations under the indentures governing the senior notes. However, under the Bankruptcy Code, holders of the senior notes were stayed from taking any action against the Predecessor as a result of the default.

Note 3—Fresh-Start Accounting

Upon our emergence from bankruptcy, we were required to adopt fresh-start accounting, which, with the recapitalization described above, resulted in Berry Corp. being treated as the new entity for financial reporting purposes.

We were required to adopt fresh-start accounting upon our emergence from bankruptcy because (i) the holders of existing voting ownership interests of our predecessor company received less than 50% of the voting shares of Berry Corp. and (ii) the reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims. An entity applying fresh-start accounting upon emergence from bankruptcy is viewed as a new reporting entity from an accounting perspective, and accordingly, may select new accounting policies.

The reorganization value of our assets immediately prior to confirmation of the Plan was less than the total of all post-petition liabilities and allowed claims, as shown below:

	(in thousands)
Liabilities subject to compromise	$ 1,000,336
Pre-petition debt not classified as subject to compromise	891,259
Post-petition liabilities	245,702
Total post-petition liabilities and allowed claims	2,137,297
Reorganization value of assets immediately prior to implementation of the Plan	(1,722,585)
Excess post-petition liabilities and allowed claims	$ 414,712

Upon adoption of fresh-start accounting, the reorganization value derived from the enterprise value was allocated to our assets and liabilities based on their fair values in accordance with GAAP. The Effective Date fair values of our assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in the financial statements as of February 28, 2017, and the related adjustments thereto were recorded on the statement of operations for the two months ended February 28, 2017.

As a result of the adoption of fresh-start accounting and the effects of the implementation of the Plan, our consolidated financial statements subsequent to February 28, 2017, are not comparable to our financial statements prior to February 28, 2017.

Our consolidated financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. 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.

Reorganization Value

Under GAAP, a value was assigned to the equity of the emerging entity as of the date of adoption of fresh-start accounting. The Plan and disclosure statement approved by the Bankruptcy Court did not include an enterprise value or reorganization value, nor did the Bankruptcy Court approve a value as part of its confirmation of our Plan. Our reorganization value was derived from an estimate of enterprise value, or the fair value of our long-term debt, stockholders' equity and working capital. Reorganization value approximates the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Based on the various estimates and assumptions necessary for fresh-start accounting, our enterprise value as of the Effective Date was estimated to be approximately $1.3 billion. The enterprise value was estimated using a sum of parts approach. The sum of parts approach represents the summation of the indicated fair value of the component assets of the Company. The fair value of our assets was estimated by relying on a combination of the income, market and cost approaches.

The estimated enterprise value, reorganization value and equity value are highly dependent on the achievement of the financial results contemplated in our underlying projections. While we believe the assumptions and estimates used to develop enterprise value and reorganization value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. Additionally, the assumptions used in estimating these values are inherently uncertain and require judgment. The primary assumptions for which there is a reasonable possibility of the occurrence of a variation that would have significantly affected the reorganization value include those regarding pricing, discount rates and the amount and timing of capital expenditures.

Our principal assets are our oil and natural gas properties. The fair values of oil and natural gas properties were estimated using a valuation technique consistent with the income approach; specifically, the discounted cash flows method. We also used the market approach to corroborate the valuation results from the income approach. We used a market-based weighted-average cost of capital discount rate of 10% for proved and unproved reserves, with further risk adjustment factors applied to the discounted values. The underlying commodity prices embedded in our estimated cash flows were based on the New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that we believe will impact realizable prices. NYMEX forward curve pricing was used for years 2017 through 2019 and then was escalated at approximately 2.0%.

See below under "Fresh-Start Adjustments" for additional information regarding assumptions used in the valuation of our various other significant assets and liabilities.

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date:

	(in thousands)
Enterprise value	$ 1,278,527
Plus: Fair value of non-debt liabilities	282,511
Reorganization value of the Successor's assets	$ 1,561,038

The fair value of non-debt liabilities consists of liabilities assumed by the Successor on the Effective Date and excludes the fair value of long-term debt.

Consolidated Balance Sheet

The adjustments included in the following fresh-start consolidated balance sheet reflect the effects of the transactions contemplated by the Plan and executed on the Effective Date (reflected in the column "Reorganization Adjustments") as well as fair value and other required accounting adjustments resulting from the adoption of fresh-start accounting (reflected in the column "Fresh-Start Adjustments"). The explanatory notes provide additional information with regard to the adjustments recorded, methods used to determine the fair values and significant assumptions.

	As of February 28, 2017			
	Berry LLC (Predecessor)	Reorganization Adjustments[1]	Fresh-Start Adjustments	Berry Corp. (Successor)
	(in thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 27,407	$ 4,642 (2)	$ —	$ 32,049
Accounts receivable	76,027	(15,700) (3)	(816) (14)	59,511
Derivative instruments	243	—	—	243
Restricted cash	128	52,732 (4)	—	52,860
Other current assets	18,437	(5,558) (5)	3,873 (15)	16,752
Total current assets	122,242	36,116	3,057	161,415
Non-current assets:				
Oil and natural gas properties	5,031,498	—	(3,787,898) (16)	1,243,600
Less accumulated depletion and amortization	(2,814,999)	—	2,814,999 (16)	—
Total oil and natural gas properties, net	2,216,499	—	(972,899)	1,243,600
Other property and equipment	124,379	—	(15,576) (17)	108,803
Less accumulated depreciation	(22,107)	—	22,107 (17)	—
Total other property and equipment, net	102,273	—	6,530	108,803
Derivative instruments	57	—	—	57
Restricted cash	197,939	(197,814) (2)	—	125
Other non-current assets	16,076	151 (6)	30,811 (18)	47,038
Total assets	$ 2,655,086	$ (161,547)	$ (932,501)	$ 1,561,038
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 60,323	$ 52,371 (7)	$ 3,818 (19)	$ 116,512
Derivative instruments	5,355	—	—	5,355
Current portion of long-term debt, net	891,259	(891,259) (8)	—	—
Other accrued liabilities	7,335	(3,760) (9)	1,295 (20)	4,870
Total current liabilities	964,272	(842,648)	5,113	126,737
Non-current liabilities:				
Derivative instruments	1,710	—	—	1,710
Long-term debt	—	400,000 (10)	—	400,000
Other non-current liabilities	170,979	—	(16,915) (21)	154,064
Liabilities subject to compromise	1,000,336	(1,000,336) (11)	—	—
Equity:				
Predecessor additional paid-in capital	2,798,714	(2,798,714) (12)	—	—
Predecessor accumulated deficit	(2,280,925)	375,159 (13)	1,905,766 (22)	—
Successor preferred stock	—	335,000 (12)	—	335,000
Successor common stock	—	33 (12)	—	33
Successor additional paid-in capital	—	3,369,959 (12)	(2,826,465) (22)	543,494
Total equity	517,789	1,281,437	(920,699)	878,527
Total liabilities and equity	$ 2,655,086	$ (161,547)	$ (932,501)	$ 1,561,038

Reorganization Adjustments:

(1) Represent amounts recorded as of the Effective Date for the implementation of the Plan, including, among other items, settlement of the Predecessor's liabilities subject to compromise, repayment of certain of the Predecessor's debt, cancellation of the Predecessor's equity,

issuances of the Successor's common stock and preferred stock, proceeds received from the Berry Rights Offerings and issuance of the Successor's debt.

(2) Changes in cash and cash equivalents included the following:

		(in thousands)
Borrowings under the Emergence Credit Facility	$	400,000
Proceeds from issuance of preferred stock pursuant the Berry Rights Offerings		335,000
Cash receipt from Linn Energy, LLC for ad valorem taxes		23,366
Removal of restriction on cash balance (includes $128 previously recorded as short term)		197,942
Payment to the holders of claims under the Pre-Emergence Credit Facility (including $29 in bank fees and $3,760 in interest)		(897,663)
Payment of professional fees		(992)
Payment of Emergence Credit Facility fee that was capitalized		(151)
Funding of the general unsecured claims Cash Distribution Pool		(35,000)
Funding of the professional fees escrow account		(17,860)
Changes in cash and cash equivalents	$	4,642

(3) Collection of overpayment to Linn Energy, LLC for ad valorem taxes.

(4) Primarily reflects the transfer to restricted cash to fund the Predecessor's professional fees escrow account and general unsecured claims Cash Distribution Pool.

(5) Primarily reflects the write-off of the Predecessor's deferred financing fees.

(6) Reflects the capitalization of deferred financing fees related to the Emergence Credit Facility.

(7) Net increase in accounts payable and accrued expenses reflects:

		(in thousands)
Recognition of payables for the general unsecured claims Cash Distribution Pool	$	35,000
Recognition of payables for the professional fees escrow account		17,860
Recognition of payable for ad valorem tax liability		7,666
Net change of other professional fees payable		(8,161)
Other		6
Net increase in accounts payable and accrued expenses	$	52,371

(8) Reflects the repayment of the Pre-Emergence Credit Facility.

(9) Reflects the payment of accrued interest on the Pre-Emergence Credit Facility.

(10) Reflects borrowings under the Emergence Credit Facility.

(11) Settlement of liabilities subject to compromise and the resulting net gains were determined as follows:

		(in thousands)
Accounts payable and accrued expenses	$	151,298
Accrued interest payable		15,238
Debt		833,800
Total liabilities subject to compromise		1,000,336
Funding of the general unsecured claims Cash Distribution Pool		(35,000)
Common stock to holders of Unsecured Notes and general unsecured creditors		(543,562)
Gains on settlement of liabilities subject to compromise	$	421,774

(12) Net increase in capital accounts reflects:

		(in thousands)
Common stock to holders of Unsecured Notes and general unsecured creditors	$	543,562
Payment of issuance costs		(35)
Dividend related to beneficial conversion feature of preferred stock		27,751
Cancellation of the Predecessor's additional paid-in capital		2,798,714
Par value of common stock		(33)
Change in additional paid-in capital		3,369,959
Proceeds from issuance of preferred stock		335,000
Par value of common stock		33
Predecessor's additional paid-in capital		(2,798,714)
Net increase in capital accounts	$	906,278

See Note 8 for additional information on the issuances and distributions of the Successor's common and preferred stock.

(13) Net decrease in accumulated deficit reflects:

		(in thousands)
Recognition of gains on settlement of liabilities subject to compromise	$	421,774
Recognition of professional fees		(13,667)
Write-off of deferred financing fees		(5,197)
Total reorganization items, net		402,910
Dividend related to beneficial conversion feature of preferred stock		(27,751)
Net decrease in accumulated deficit	$	375,159

Fresh-Start Adjustments:

(14) Reflects a change in accounting policy from the entitlements method to the sales method for natural gas production imbalances.

(15) Primarily reflects an increase in the current portion of greenhouse gas allowances.

(16) Reflects a decrease of oil and natural gas properties, based on the methodology discussed in Note 4, and the elimination of accumulated depletion and amortization. The following table summarizes the components of oil and natural gas properties as of the Effective Date:

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	Fair Value	Historical Book Value
	(in thousands)	
Proved properties	$ 712,400	$ 4,266,843
Unproved properties	531,200	764,655
Total proved and unproved properties	1,243,600	5,031,498
Less accumulated depletion and amortization	—	(2,814,999)
Total proved and unproved properties, net	$ 1,243,600	$ 2,216,499

(17) Reflects a decrease of other property and equipment and the elimination of accumulated depreciation. The following table summarizes the components of other property and equipment as of the Effective Date:

	Berry Corp. (Successor)	Berry LLC (Predecessor)
	Fair Value	Historical Book Value
	(in thousands)	
Natural gas plants and pipelines	$ 91,427	$ 109,675
Land	8,262	201
Furniture and office equipment	5,040	3,879
Buildings and leasehold improvements	2,740	5,884
Vehicles	1,156	4,542
Drilling and other equipment	178	198
Total other property and equipment	108,803	124,379
Less accumulated depreciation	—	(22,107)
Total other property and equipment, net	$ 108,803	$ 102,273

In estimating the fair value of other property and equipment, we used a combination of cost and market approaches. A cost approach was used to value our natural gas plants and pipelines, buildings, and furniture and office equipment based on current replacement costs of the assets less depreciation based on the estimated economic useful lives of the assets and age of the assets. A market approach was used to value our vehicles, drilling and other equipment, and land, using recent transactions of similar assets to determine the fair value from a market participant perspective.

(18) Primarily reflects an increase in greenhouse gas allowances of approximately $30 million and a joint venture investment of approximately $1 million. Greenhouse gas allowances were valued using a market approach based on trading prices for carbon credits on February 28, 2017. Our joint venture investment was valued based on a market approach using a market EBITDA multiple.

(19) Reflects increases for greenhouse gas emissions liabilities of approximately $4 million and a change in accounting policy from the entitlements method to the sales method for gas production imbalances of approximately $200,000, partially offset by a decrease for the current portion of intangibles liabilities of approximately $500,000.

(20) Reflects an increase of the current portion of asset retirement obligations.

(21) Primarily reflects a decrease for asset retirement obligations of approximately $30 million and for intangible liabilities of approximately$6 million, partially offset by an increase for greenhouse gas emissions liabilities of approximately $19 million. The fair value of asset retirement obligations was estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plugging and abandonment costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. The intangible liabilities identified on the Effective Date were valued based on a combination of market and incomes approaches and will be amortized over the remaining life of the respective contract. Greenhouse gas emissions liabilities were valued using a market approach based on trading prices for greenhouse gas allowances on February 28, 2017.

(22) Reflects the cumulative impact of the fresh-start accounting adjustments discussed above and the elimination of the Predecessor's accumulated deficit.

Note 4—Oil and Natural Gas Properties and Other Property and Equipment

Oil and Natural Gas Capitalized Costs

As a result of the application of fresh-start accounting, we recorded our oil and natural gas properties and other property and equipment at fair value as of the Effective Date. The fair values of oil and natural gas properties were measured 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 and unproved properties include estimates of i) reserves ii) future operating and development costs iii) future commodity prices and (iv) a market-based weighted-average cost of capital rate. These inputs required significant judgments and estimates at the time of the valuation and are the most sensitive and subject to change of our inputs. The fair value was estimated using inputs characteristic of a Level 3 fair value measurement.

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

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Proved properties	$ 1,073,959	$ 825,416
Unproved properties	388,034	517,037
Total proved and unproved properties	1,461,993	1,342,453
Less accumulated depletion and amortization	(123,217)	(54,785)
Total proved and unproved properties, net	$ 1,338,776	$ 1,287,668

Other Property and Equipment

Other property and equipment consisted of the following:

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Natural gas plants and pipelines	$ 86,562	$ 79,856
Buildings and leasehold improvements	3,359	2,986
Vehicles	6,753	3,228
Furniture and equipment	14,964	10,547
Land	8,073	8,262
Total other property and equipment	119,710	104,879
Less: accumulated depreciation	(15,778)	(5,356)
Total other property and equipment, net	$ 103,932	$ 99,523

Note 5—Debt

The following table summarizes our outstanding debt:

	December 31, 2018	December 31, 2017	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ 379,000	variable rates of 4.5% (2018) and 4.8% (2017), respectively	June 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves
2026 Notes	400,000	—	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	379,000			
Less: Debt Issuance Costs	(8,214)	—			
Long-Term Debt, net	$ 391,786	$ 379,000			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At December 31, 2018 and December 31, 2017, debt issuance costs for the RBL Facility (as defined below) reported in "other non-current assets" on the balance sheet were approximately $16 million and $20 million net of amortization, respectively. The amortization of debt issuance costs is presented in interest expense on the statements of operations. At December 31, 2018, debt issuance costs for the 2026 Notes (as defined below) were $8 million net of amortization.

For the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, amortization expense of approximately $4 million, $2 million, zero and $2 million was included in "interest expense" in the consolidated statements of operations.

Fair Value

Our debt was 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 senior unsecured notes was approximately $368 million at December 31, 2018.

Credit Facilities

On July 31, 2017, we entered into a credit agreement (the "RBL Facility"), with Wells Fargo Bank, N.A. as administrative agent and certain lenders with up to $1.5 billion of commitments, subject to a reserve borrowing base. The RBL Facility also 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 become effective on or about each May 1 and November 1, although each of the administrative agent and Berry LLC 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 2018, we completed a borrowing base redetermination under our RBL Facility that increased our borrowing base from $400 million to $850 million and reaffirmed our elected commitment amount at $400 million. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms.

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 2.50% to 3.50% per annum, and (ii) a customary base rate plus an applicable margin ranging from 1.50% to 2.50% per annum, in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.50% 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.

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 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.

As of December 31, 2018, the financial performance covenants under our RBL Facility were (i) a leverage ratio of no more than 4.00 to 1.00 and (ii) a current ratio of at least 1.00 to 1.00. At December 31, 2018, our actual ratios were 1.63 to 1.00 and 3.73 to 1.00, 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 as of December 31, 2018.

As of December 31, 2018, we had approximately $393 million of available borrowing capacity under the RBL Facility.

As of December 31, 2018 and December 31, 2017, we had letters of credit outstanding of approximately $7 million and $21 million, respectively, under our RBL Facility. These letters of credit were issued to support ordinary course of business marketing, insurance, regulatory and other matters.

In July and August 2018, we paid down approximately $105 million on the RBL Facility from the net proceeds we received in the IPO of our common stock (see Note 8).

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 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, 2018.

Note 6—Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices. We target covering our operating expenses and fixed charges, including maintenance capital expenditures, for up to two years out. We have hedged a portion of our exposure to differentials between Intercontinental Exchange (“ICE”) Brent oil (“Brent”) and NYMEX West Texas Intermediate oil (“WTI”) as well. 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.

As of February 28, 2019, our hedge position consisted of oil swaps and puts and natural gas swaps. We use oil swaps and puts to protect against decreases in the oil price and natural gas swaps to protect against increases in natural gas 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. We did not designate any of our contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. Gains (losses) on oil hedges are classified in the revenues and other section of the statement of operations and gains (losses) on natural gas hedges are presented in the expenses and other section of the statement of operations.

As of December 31, 2018, we have hedged crude oil production at the following approximate volumes and prices: 17.5 MBbl/d at $70 per barrel in 2019 and 1.2 MBbl/d at $65 per barrel in 2020, as outlined along with our natural gas derivative contracts in the following table:

	Q1 2019	Q2 2019	Q3 2019	Q4 2019	FY 2020
Purchased Oil Put Options (ICE Brent):					
Hedged volume (MBbls)	360	1,001	1,012	1,012	455
Weighted-average price ($/Bbl)	$ 65.00	$ 65.00	$ 65.00	$ 65.00	$ 65.00
Fixed Price Oil Swaps (ICE Brent):					
Hedged volume (MBbls)	1,080	637	644	644	—
Weighted-average price ($/Bbl)	$ 75.76	$ 76.27	$ 76.27	$ 76.27	$ —
Oil basis differential positions (ICE Brent-NYMEX WTI basis swaps):					
Hedged volume (MBbls)	45	45.5	46	46	—
Weighted-average price ($/Bbl)	$ (1.29)	$ (1.29)	$ (1.29)	$ (1.29)	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):					
Hedged volume (MMBtu)	1,350,000	1,365,000	1,380,000	465,000	—
Weighted-average price ($/MMBtu)	$ 2.65	$ 2.65	$ 2.65	$ 2.65	$ —

In January and February 2019, we closed a portion of our deferred premium put positions by selling offsetting put positions and terminating contracts. We also added to our natural gas swap positions we had previously hedged. As of February 28, 2019, we had hedged approximately 15.3 MBbl/d of our 2019 crude oil production at $68 per barrel.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our put positions, we paid the premium at the time the positions were created, and for others, we will pay the premium at the time of settlement. In order to mitigate the exposure to these deferred premiums, we have entered into several offsetting put positions. The purchased put options contain deferred premiums of approximately $20 million and are reflected in the mark-to-market valuation of the derivatives on the balance sheet at December 31, 2018. The premiums will be payable in conjunction with the monthly settlements of these contracts and thus have been deferred until payments begin in 2019.

For fixed-price swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent.

For oil basis swaps, we make settlement payments if the difference between Brent and WTI is greater than the indicated weighted-average price per barrel of our contracts and receive settlement payments if the difference between Brent and WTI is below the indicated weighted-average price per barrel.

For fixed-price natural 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.

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. The following tables present the fair values (gross and net) of our outstanding derivatives as of December 31, 2018 and December 31, 2017:

	Berry Corp. (Successor)			
	December 31, 2018			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset on Balance Sheet	Net Fair Value Presented on Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 89,981	$ (1,385)	$ 88,596
Commodity Contracts	Non-current assets	3,289	—	3,289
Liabilities:				
Commodity Contracts	Current liabilities	(1,385)	1,385	—
Total derivatives		$ 91,885	$ —	$ 91,885

	Berry Corp. (Successor)			
	December 31, 2017			
	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)		
Liabilities:				
Commodity Contracts	Current liabilities	$ (49,949)	$ —	$ (49,949)
Commodity Contracts	Non-current liabilities	(25,332)	—	(25,332)
Total derivatives		$ (75,281)	$ —	$ (75,281)

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 and Brent oil purchased put options for January 2019 through March 2020. These Brent oil swaps hedged 1.8 MMBbls in 2018 and 0.9 MMBbls in 2019 at a weighted-average price of $75.66. These Brent oil purchased put options provided a weighted-average price floor of $65.00 for 2.8 MMBbls in 2019 and 0.5 MMBbls in 2020. We effected these transactions to move from a WTI-based position to a Brent-based position as well as bring our hedge pricing more in line with market pricing at the time.

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk and market 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 mitigates the counterparty nonperformance risk somewhat.

Gains (Losses) on Derivatives

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Gains (losses) on oil derivatives	$ (4,621)	$ (66,900)	$ 12,886	$ (15,781)
Gains (losses) on natural gas derivatives	6,357	—	—	—
Lease operating expenses[(1)]	—	—	—	(4,605)
Total gains (losses) on oil and natural gas derivatives	$ (1,735)	$ (66,900)	$ 12,886	$ (20,386)

(1) Consists of gains and (losses) on derivatives that were entered into in March 2015 to hedge exposure to differentials in consuming areas.

For the year ended December 31, 2018, we paid net cash scheduled settlements of approximately $38 million, excluding the payments for the early terminated derivatives. For the ten months ended December 31, 2017, the two months ended February 28, 2017 and the year ended December 31, 2016, we received net cash settlements of approximately $3 million, $0.5 million, and $10 million, respectively.

Note 7—Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

On May 11, 2016 our predecessor company filed the Chapter 11 Proceeding. Our bankruptcy case was jointly administered with that of Linn Energy and its affiliates under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court approved and confirmed the Plan. On February 28, 2017, the Effective Date occurred and the Plan became effective and was implemented. 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.

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, 2018 and December 31, 2017. 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, 2018, 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. At December 31, 2018, we had an obligation to provide improved road access in connection with our Piceance assets. Our obligation is for a minimum $6 million, which could be higher if we elect to construct, or begin construction of the road, in which case we are obligated to cover 100% of the first $9 million of construction costs plus 50% of the all construction costs above $9 million. Alternatively, we can provide long-term access to an existing road. In addition, we entered into certain firm commitments to secure transportation of our natural gas production to market as well as pipeline and processing capacity which require a minimum monthly charge regardless of whether the contracted capacity is used or not. We have also entered into operating lease agreements mainly for office space. Lease payments are generally expensed as part of general and administrative expenses. At December 31, 2018, 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:

	2019	2020	2021	2022	2023	Thereafter	Total
				(in thousands)			
Minimum purchase obligations	$ 3,195	$ 3,247	$ 2,675	$ 2,590	$ 1,061	—	$ 12,768
Minimum lease payments	$ 1,290	$ 316	$ 321	$ 326	$ 229	$ —	$ 2,482

Note 8—Equity

On the Effective Date, 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 Petroleum Corporation (the "Series A Certificate of Designation"). Berry Corp. also adopted the Amended and Restated Bylaws of Berry Petroleum Corporation (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.

Common Stock

The Plan contemplated the distribution of 40,000,000 shares of common stock in Berry Corp. On the Effective Date, 32,920,000 shares of common stock were distributed, pro rata, to holders of Unsecured Notes claims. The holders of Unsecured Claims received a right to receive their pro rata 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. Since the Effective Date we have negotiated with claimants to settle their claims and subsequent to December 31, 2018 we issued approximately 2,770,000 shares instead of 7,080,000 to resolve these claims.

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, 2018.

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. No dividends had been declared or paid as of December 31, 2017. The accreted cumulative and per share value of the dividends as of December 31, 2017 was approximately $18 million and $0.51, respectively.

In March 2018, the board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board of directors approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018 to be paid in April 2018.

Beneficial Conversion Feature

A beneficial conversion feature exists when the effective conversion price of a convertible security is less than the fair value per share on the commitment date. The conversion price of the preferred stock on the date of issuance was less than the estimated fair value of the common stock distributable under the Plan. Since the preferred stock is not mandatorily redeemable and is immediately convertible, the entire amount of the beneficial conversion feature was recognized immediately. In accordance with GAAP, we recorded a non-cash deemed dividend and a corresponding increase to additional paid in capital of approximately $27 million that is attributable to this beneficial conversion feature. The financial statement impact of the deemed dividend is eliminated in the consolidated statement of equity as adopting fresh-start accounting results in an entity with no beginning retained earnings or accumulated deficit.

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.

The Registration Rights Agreement requires Berry Corp. to file a shelf registration statement with the SEC as soon as practicable following 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, (ii) preferred stock that was purchased by the participants in the Berry Rights Offerings 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, 2018, there were 81,202,438 shares of common stock issued and outstanding under the Company's Omnibus Incentive Plan. An additional 922,952 unvested restricted stock units and performance restricted stock units were outstanding under the Company's 2017 Omnibus Incentive Plan as of December 31, 2018. A further 7,080,000 common shares were reserved for issuance to the general unsecured creditor group (the "Unsecured Claims") pending resolution of disputed claims. Subsequent to December 31, 2018, we resolved such disputed claims by issuing approximately 2,770,000 shares. See Note 2 under "*Plan of Reorganization*" and Note 14 for further discussion of the common shares set aside to settle claims.

In March 2018, the board of directors approved a cumulative paid-in-kind dividend on the Series A Preferred Stock for the periods through December 31, 2017. The cumulative dividend was 0.050907 per share and approximately 1,825,000 shares in total. Also in March 2018, the board approved a $0.158 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended March 31, 2018. In both cases, the payments were to stockholders of record as of March 15, 2018. In May 2018, the board of directors approved a $0.15 per share, or approximately $5.6 million, cash dividend on the Series A Preferred Stock for the quarter ended June 30, 2018. The payment was to stockholders of record as of June 7, 2018. As described above, 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 following the IPO.

On August 21, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock on a pro-rated basis from the date of our IPO through September 30, 2018, which resulted in a payment of $0.09 per share in October 2018. On November 7, 2018, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the fourth quarter of 2018, which was paid in January 2019. On February 28, 2019, our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the first quarter of 2019.

Purchase of rights to common stock

In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. As a result, we paid approximately $20 million to purchase their claims to our common stock that we have reflected as treasury stock.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of current market conditions for our common stock they authorized current repurchases of up to $50 million under the program. Purchases may be made from time to time in the open market, in privately negotiated transactions or otherwise. 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 Petroleum to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. In December 2018, we repurchased 448,661 shares at an average price of $8.81 per share for $4 million, which is reflected as treasury stock. The Company repurchased 1,932,096 shares from January 1, 2019 through February 28, 2019, resulting in a total of 2,380,757 shares repurchased under the Stock Repurchase Program for $25 million as of February 28, 2019.

Stock-Based Compensation

In July 2018, we became a public company and our stock began trading on the NASDAQ. As a result, the fair value of our common stock underlying our stock-based compensation awards granted will no longer be based on complex models using inputs and assumptions, but will be based on the price of our stock at the date of grant.

On June 27, 2018, our board of directors adopted the Berry Petroleum Corporation 2017 Omnibus Incentive 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 8,381,902 as of December 31, 2018.

For the year ended December 31, 2018, ten months ended December 31, 2017 and two months ended February 28, 2017 the stock-based compensation expense was $7 million, $2 million and zero, respectively. For the year ended December 31, 2018, stock-based compensation had an income tax benefit of approximately $1.5 million.

The table below summarizes the activity relating to restricted stock units ("RSUs") issued under the 2017 Plan during the year ended December 31, 2018. The RSUs vest ratably over three years. Unrecognized compensation cost associated with the RSUs at December 31, 2018 was approximately $5 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)		
December 31, 2017	683	$	10.12
Granted	218	$	11.97
Vested	(239)	$	10.24
Forfeited	(21)	$	10.92
December 31, 2018	641	$	10.82

The table below summarizes the activity relating to the performance-based restricted stock units ("PSUs") issued under the 2017 Plan during the year ended December 31, 2018. The PSUs vest if the Company's stock price reaches certain levels over defined periods of time. Unrecognized compensation cost associated with the PSUs at December 31, 2018 is approximately $1 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)	
December 31, 2017	622	$ 7.09
Granted	132	$ 7.98
Vested	(454)	$ 7.78
Forfeited	(18)	$ 7.49
December 31, 2018	282	$ 6.73

In November 2018, we granted equity awards to executive officers consisting of 40% RSUs and 60% PSUs, under and pursuant to the terms of Omnibus Plan with the number of shares covered by such awards determined as of March 1, 2019. The time-vested RSUs will vest in equal annual increments over a three-year period with the first installment vesting March 1, 2020, subject to continued employment. The PSUs will vest, if at all, based on our total stockholder return, or the capital gains per share plus dividends paid assuming reinvestment over the performance period of July 26, 2018 through December 31, 2020.

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 issuing and 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 of $14.00 per share for which we did not receive any proceeds.

Note 9—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. The 401(k) plan provides for a matching contribution of up to 6% of an employee's eligible compensation. Employees are eligible to participate in the 401(k) plan on their date of hire.

We expensed approximately $1.4 million, $0.8 million, $0 and $0 for the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017 and the year ended December 31, 2016, respectively, under the provisions of the 401(k) plan.

Note 10—Income taxes

Prior to the Effective Date, Berry LLC was a limited liability company treated as a disregarded entity for federal and state income tax purposes, with the exception of the state of Texas. Limited liability companies are subject to Texas margin tax. As such, with the exception of the state of Texas, Berry LLC was not a taxable entity, it did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of Berry LLC. Upon emergence from bankruptcy, Berry Corp. acquired the assets of Berry LLC in a taxable asset acquisition as part of the restructuring. Consequently, we are now taxed as a corporation and have no net operating loss carryforwards for the periods prior to February 28, 2017.

On December 22, 2017, the U.S. Tax Cuts and Jobs Act (the "Act") made significant changes to the Internal Revenue Code of 1986, including lowering the maximum federal corporate income tax rate from 35% to 21% and imposing limitations on the use of net operating losses arising in taxable years ending after December 31, 2017. The SEC permitted the recognition of provisional amounts based on a reasonable estimate, subject to adjustments in a one-year measurement period. For the year ended December 31, 2017, we recorded provisional estimates for the remeasurement of our net deferred tax asset before valuation allowance of $2.7 million for the reduction in the corporate tax rate and a $1.9 million increase in the valuation allowance as a result of the Act. During 2018, we completed our accounting related to the income tax effects of the Act, resulting in no significant adjustments to the provisional amounts recorded.

The key contributor to the change in our effective rate from (15)% in the ten months ended December 31, 2017 to 23% for the year ended December 31, 2018 was the reduction in the valuation allowance. Our earnings for 2018 allowed for the release of our valuation allowance, described below, resulting in an effective tax rate less than the statutory federal and state tax rates.

Income tax expense (benefit) consisted of the following:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Current taxes:				
Federal	$ (465)	$ 465	$ —	$ —
State	(446)	450	221	127
Total current taxes	(911)	915	221	127
Deferred taxes:				
Federal	33,227	1,888	—	—
State	10,719	—	9	(11)
Total deferred taxes	43,946	1,888	9	(11)
Total current and deferred taxes	$ 43,035	$ 2,803	$ 230	$ 116

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Federal statutory rate	21.0 %	35.0 %	35.0 %	35.0 %
State, net of federal tax benefit	6.3 %	7.2 %	— %	— %
Effect of permanent differences	(0.6)%	(0.4)%	— %	— %
Tax reform—rate change[(1)]	— %	(14.7)%	— %	— %
Income excluded from nontaxable entities	— %	— %	(35.0)%	(35.0)%
Change in valuation allowance	(4.1)%	(42.4)%	— %	— %
Effective tax rate	22.6 %	(15.3)%	— %	— %

(1) For the ten months ended December 31, 2017, includes the tax rate reduction. The impact of the rate change is fully offset in the "Change in valuation allowance" item.

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

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 14,310	$ 1,556
Accruals	2,993	2,144
Asset retirement obligations	26,383	27,064
Derivative instruments	—	18,982
Tax credits	—	528
Interest limitation carryforward	7,486	—
Other	2,033	867
Subtotal	53,205	51,141
Valuation allowance	—	(7,748)
Total deferred tax assets	53,205	43,393
Deferred tax liabilities:		
Book tax differences in property basis	(95,348)	(45,281)
Derivative instruments	(3,692)	—
Total deferred tax liabilities	(99,040)	(45,281)
Net deferred tax asset (liability)	$ (45,835)	$ (1,888)

We assessed the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of the existing deferred tax assets. As of December 31, 2018, due to the positive evidence of cumulative income since the Effective Date and the reversal of existing federal and state temporary differences, we determined there is sufficient positive evidence to conclude that it is more likely than not that our deferred tax assets are realizable. Therefore, we have fully released the valuation allowance in 2018, resulting in an income tax benefit of $7.7 million.

As of December 31, 2018, the Company had approximately $55 million of federal net operating loss ("NOL") carryforwards and $45 million of state net operating loss carryforwards. $25 million of federal net operating loss carryovers have no expiration date and the remaining expire in 2037. State net operating loss carry forwards will expire in varying amounts beginning in 2037.

The Act signed into law in 2017 imposed new limitations to Code Section 163(j), restricting the ability to deduct interest paid or accrued on indebtedness. As of December 2018, we recorded a deferred tax asset for the benefit of the interest deduction carryforward in the amount of $7.5 million. The interest carryforward has an indefinite life.

We had no material uncertain tax positions at December 31, 2018. We do not believe that it is reasonably possible 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 taxing authority. The 2018 and 2017 federal and state tax returns remain open to examination under the respective statute of limitations.

Note 11—Supplemental Disclosures to the Balance Sheets and Statements of Cash Flows

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

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Prepaid expenses	$ 4,656	$ 6,901
Oil inventories, materials and supplies	9,473	5,938
Other	238	1,227
Other current assets	$ 14,367	$ 14,066

The major classes of inventory were not material and therefore not stated separately. Other non-current assets at December 31, 2018 and December 31, 2017 included approximately $16 million and $20 million of deferred financing costs, net of amortization, respectively.

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

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Accounts payable-trade	$ 13,564	$ 11,916
Accrued expenses	66,417	37,912
Royalties payable	26,189	25,793
Greenhouse gas liability	—	10,446
Taxes other than income tax liability	10,766	8,437
Accrued interest	10,500	—
Dividends payable	9,992	—
Other	6,689	3,373
Total accounts payable and accrued expenses	$ 144,118	$ 97,877

Other non-current liabilities at December 31, 2018 included approximately $15 million of greenhouse gas liability.

Supplemental Cash Flow Information

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Supplemental Disclosures of Significant Non-Cash Investing Activities:				
Increase (decrease) in accrued liabilities related to purchases of property and equipment	$ 19,257	$ 2,483	$ 2,249	$ 2,266
Supplemental Disclosures of Cash Payments (Receipts):				
Interest, net of amounts capitalized	$ 19,761	$ 14,276	$ 8,057	$ 57,759
Income taxes	$ (1,901)	$ 1,994	$ —	$ 347
Reorganization items, net	$ 832	$ 1,732	$ 11,838	$ 19,116

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:

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	December 31, 2018	December 31, 2017	February 28, 2017	December 31, 2016
	(in thousands)			
Beginning of Period				
Cash and cash equivalents	$ 33,905	$ 32,049	$ 30,483	$ 1,023
Restricted cash	34,833	52,860	197,793	250,359
Restricted cash in other noncurrent assets	—	125	128	128
Cash, cash equivalents and restricted cash	$ 68,738	$ 85,034	$ 228,404	$ 251,510
Ending of Period				
Cash and cash equivalents	$ 68,680	$ 33,905	$ 32,049	$ 30,483
Restricted cash	—	34,833	52,860	197,793
Restricted cash in other noncurrent assets	—	—	125	128
Cash, cash equivalents and restricted cash	$ 68,680	$ 68,738	$ 85,034	$ 228,404

Restricted cash is associated with cash reserved to settle claims with general unsecured creditors resulting from implementation of the Plan. 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.

Note 12—Certain Relationships and Related Party Transactions

In connection with our emergence from bankruptcy, we entered into agreements with certain of our affiliates and with parties who received shares of our common stock and Series A Preferred Stock in exchange for their claims. See Note 8 - Equity for further details.

Transition Services and Separation Agreement ("TSSA")

On the Effective Date, Berry LLC entered into a TSSA with Linn Energy and certain of its subsidiaries to facilitate the separation of Berry LLC's operations from Linn Energy's operations. Under the TSSA, Berry LLC reimbursed Linn Energy for third-party out-of-pocket costs and expenses actually incurred by Linn Energy in connection with providing certain transition services. Additionally, Berry LLC paid to Linn Energy a management fee equal to $6 million per month, prorated for partial months, during the period from the Effective Date through the last day of the second full calendar month after the Effective Date (the "Transition Period") and $2.7 million per month, prorated for partial months, from the first day following the Transition Period through the last day of the second full calendar month thereafter (the "Accounting Period"). During the Accounting Period, the scope of the transition services was reduced to specified accounting and administrative services. The Transition Period under the TSSA ended April 30, 2017, and the Accounting Period ended June 30, 2017. For the seven months ended September 30, 2017, we incurred management fee expenses of approximately $17 million under the TSSA. Since the agreement commenced on the Effective Date, no expenses were incurred for the periods ended February 28, 2017.

Note 13—Acquisitions and Divestitures

Acquisition of Hill Properties

On July 31, 2017, we acquired the remaining 84% working interest in the South Belridge Hill property located in Kern County, California, in which we previously owned a 16% working interest (the "Hill Acquisition"). We purchased the properties for approximately $249 million.

Chevron North Midway-Sunset Acquisition

In April 2018, we acquired 2 leases on an aggregate of 214 acres and a lease option on 490 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, 2022. We had not drilled any of these wells as of December 31, 2018. We would assume an additional 40 well drilling commitment if we exercise our option on the 490 acres. 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.

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.

Disposition of Hugoton Properties

On July 31, 2017, we divested our 78% working interest in the Hugoton natural gas field located in Southwest Kansas and the Oklahoma Panhandle (the "Hugoton Disposition") because we deemed it a non-core asset. This resulted in approximately $234 million of proceeds and a $23 million gain.

Note 14—Earnings Per Share

The Predecessor was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the predecessor company periods.

We calculate basic earnings (loss) per share by dividing net income (loss) attributable to common stockholders by the weighted-average number of common shares outstanding during each period. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, such as those shares contemplated by the Plan, are considered common shares outstanding and are included in the computation of net income (loss) per share. The Plan required that we reserve 7,080,000 shares of our common stock to settle claims of unsecured creditors. These shares were previously included in the 40 million shares of common stock contemplated by the Plan, without regard to actual issuance dates. Prior to the finalization and issuance of these shares, the computation of net income (loss) per share included the 7,080,000 reserved shares. In March 2019, we finalized settlement of these claims, 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.

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 year ended December 31, 2018 as their effect was anti-dilutive under the "if-converted" method. The RSUs are not a participating security as the dividends are forfeitable. The incremental RSU shares of 189,000 were included in the diluted EPS calculation for the year ended December 31, 2018 as their effect was dilutive under the "if-converted" method. No incremental shares of Series A Preferred Stock or RSUs were included in the diluted EPS calculation for the ten months ended December 31, 2017 as their effect was anti-dilutive under the "if-converted" method. No PSUs were included in the EPS calculations for any of the periods presented due to their contingent nature.

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 8). 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.

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	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)			
Basic EPS calculation				
Net income (loss)	$ 147,102	$ (21,068)	n/a	n/a
less: Series A Preferred Stock dividends and conversion to common stock	(97,942)	(18,248)	n/a	n/a
Net income (loss) attributable to common stockholders	$ 49,160	$ (39,316)	n/a	n/a
Weighted-average shares of common stock outstanding	57,743	38,644	n/a	n/a
Basic Earnings (loss) per share[(2)]	$ 0.85	$ (1.02)	n/a	n/a
Diluted EPS calculation				
Net income (loss)	$ 147,102	$ (21,068)	n/a	n/a
less: Series A Preferred Stock dividends and conversion to common stock	(97,942)	(18,248)	n/a	n/a
Net loss attributable to common stockholders	$ 49,160	$ (39,316)	n/a	n/a
Weighted-average shares of common stock outstanding	57,743	38,644	n/a	n/a
Dilutive effect of potentially dilutive securities[(1)]	189	—	n/a	n/a
Weighted-average common shares outstanding-diluted	57,932	38,644	n/a	n/a
Diluted Earnings (loss) per share[(2)]	$ 0.85	$ (1.02)	n/a	n/a

(1) No potentially dilutive securities were included in computing earnings (loss) per share for the ten months ended December 31, 2017 because the effect of inclusion would have been anti-dilutive.

(2) Per share amounts are stated net of tax.

BERRY PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY FINANCIAL DATA
(Unaudited)

	Berry Corp. (Successor)			
	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
2018:				
Total revenues and other[1]	$ 97,284	$ 65,982	$ 142,947	$ 280,346
Total expenses[2]	$ 91,121	$ 90,458	$ 102,130	$ 104,743
(Gains) losses on sale of assets and other, net	$ —	$ 123	$ 400	$ (3,269)
Reorganization items, net, expense (income)	$ 8,955	$ 456	$ 13,781	$ 1,498
Net income (loss)	$ 6,410	$ (28,061)	$ 36,985	$ 131,768
Net income (loss) attributable to common stockholders	$ 760	$ (33,711)	$ (49,657)	$ 131,768
Earnings (loss) per share attributable to common stockholders:				
Basic[4]	$ 0.02	$ (0.94)	$ (0.70)	$ 1.56
Diluted[4]	$ 0.02	$ (0.94)	$ (0.70)	$ 1.56

	Berry LLC (Predecessor)	Berry Corp. (Successor)			
	Two Months Ended February 28	One Month Ended March 31	Quarters Ended		
			June 30	September 30	December 31
	(in thousands, except per share amounts)				
2017:					
Total revenues and other[1]	$ 92,718	$ 59,655	$ 134,721	$ 69,910	$ 55,382
Total expenses[2]	$ 79,607	$ 37,783	$ 113,380	$ 101,397	$ 92,189
(Gains) losses on sale of assets and other, net	$ (183)	$ —	$ 5	$ (20,692)	$ (2,243)
Reorganization items, net, expense (income)	$ 507,720	$ 1,306	$ (713)	$ 408	$ 730
Net income (loss)	$ (502,964)	$ 11,377	$ 12,119	$ (9,684)	$ (34,880)
Net income (loss) attributable to common stockholders	$ (502,964)	$ 9,585	$ 6,715	$ (15,169)	$ (40,447)
Earnings (loss) per share attributable to common stockholders:					
Basic[3][4]	n/a	$ 0.25	$ 0.17	$ (0.39)	$ (1.05)
Diluted[3][4]	n/a	$ 0.15	$ 0.16	$ (0.39)	$ (1.05)

BERRY PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Continued)
(Unaudited)

	Berry LLC (Predecessor)[3]			
	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
2016:				
Total revenues and other[1]	$ 91,266	$ 108,639	$ 113,225	$ 97,861
Total expenses[2]	$ 1,196,393	$ 133,868	$ 111,600	$ 118,207
(Gains) losses on sale of assets and other, net	$ (192)	$ 425	$ (370)	$ 28
Reorganization items, net expense (income)	$ —	$ (49,086)	$ 87,915	$ 33,833
Net income (loss)	$ (1,124,819)	$ 6,840	$ (98,438)	$ (66,779)

(1) Includes net derivative gains (losses) for oil sales derivatives.
(2) Includes the following expenses: lease operating, electricity generation, transportation, marketing, general and administrative, depreciation, depletion and amortization, impairment of long-lived assets, taxes, other than income taxes, and gains or losses on natural gas derivatives.
(3) Our predecessor company was organized as a limited liability company and, as such, did not issue any stock. Accordingly, we have not presented earnings per share calculations for the predecessor company periods.
(4) 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 14 of our consolidated financial statements for further information.

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

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

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

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Property acquisition costs:				
Proved	$ —	$ 249,338	$ —	$ 1,545
Unproved	—	—	—	—
Exploration costs	—	—	—	—
Development costs[1]	143,002	60,381	4,544	13,091
Total costs incurred	$ 143,002	$ 309,719	$ 4,544	$ 14,636

(1) Included in development costs for the year ended December 31, 2018 are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $3.4 million.

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:

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	(in thousands)	
Proved properties	$ 1,168,245	$ 911,478
Unproved properties	388,034	517,037
Total proved and unproved properties	1,556,279	1,428,515
Less accumulated depreciation, depletion and amortization	(132,587)	(58,525)
Net capitalized costs	$ 1,423,692	$ 1,369,990

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

Results of Oil and Natural Gas Producing Activities

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
	(in thousands)			
Net revenues from production:				
Oil, natural gas and NGL sales	$ 552,874	$ 357,928	$ 74,120	$ 392,345
Electricity sales	35,208	21,972	3,655	23,204
Other production-related revenue	2,908	6,569	2,003	10,899
Total net revenues from production	590,990	386,469	79,778	426,448
Operating costs for production:				
Lease operating expenses	188,776	149,599	28,238	185,056
Electricity generation expenses	20,619	14,894	3,197	17,133
Transportation expenses	9,860	19,238	6,194	41,619
Production-related general and administrative expenses	1,876	5,786	—	—
Taxes, other than income taxes	33,117	34,211	5,212	24,982
Other production-related costs	2,140	2,320	653	3,100
Total operating costs for production	256,388	226,048	43,494	271,890
Other costs:				
Depreciation, depletion and amortization	81,927	67,051	26,743	169,605
Impairment of long-lived assets	—	—	—	1,030,588
(Gains) losses on sale of assets and other, net	(2,747)	(22,930)	—	(7)
Total other costs	79,180	44,121	26,743	1,200,186
Pretax income (loss)	255,422	116,300	9,541	(1,045,628)
Income tax expense	69,807	45,887	230	116
Results of operations	$ 185,615	$ 70,412	$ 9,311	$ (1,045,743)

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. There is no federal tax provision included in the Predecessors results above because the Predecessor was not subject to federal income taxes during those periods. The income tax amount included in the Predecessor’s results above relates to Texas margin tax expense. Limited liability companies are subject to Texas margin tax. See Note 10 for additional information about income taxes.

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

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, 2018, December 31, 2017 and December 31, 2016 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, 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	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	32,106	—	136,720	54,893
End of year	41,562	100	84,518	55,749

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

	Year Ended December 31, 2017			
	Oil MBbls	NGLs MBbls	Natural Gas MMcf	Total MBoe
Total proved reserves:				
Beginning of year (Predecessor)	55,876	15,078	372,760	133,080
Revisions of previous estimates	9,089	431	32,144	14,878
Sales of proved reserves in place	(13)	(13,329)	(285,168)	(60,870)
Purchase of proved reserves in place	24,332	—	—	24,332
Extensions and discoveries	18,783	—	136,719	41,570
Production	(7,471)	(909)	(19,351)	(11,605)
End of year	100,596	1,271	237,104	141,385
Proved developed reserves:				
Beginning of year (Predecessor)	55,422	15,078	372,760	132,626
End of year	68,490	1,271	100,384	86,492
Proved undeveloped reserves:				
Beginning of year (Predecessor)	454	—	—	454
End of year	32,106	—	136,720	54,893

	Year Ended December 31, 2016			
	Oil MBbls	NGLs MBbls	Natural Gas MMcf	Total MBoe
Total proved reserves:				
Beginning of year (Predecessor)	93,892	16,953	387,848	175,487
Revisions of previous estimates	(31,350)	(568)	13,311	(29,701)
Extensions and discoveries	1,797	—	178	1,827
Production	(8,463)	(1,307)	(28,577)	(14,533)
End of year (Predecessor)	55,876	15,078	372,760	133,080
Proved developed reserves:				
Beginning of year (Predecessor)	93,892	16,953	387,848	175,487
End of year (Predecessor)	55,422	15,078	372,760	132,626
Proved undeveloped reserves:				
Beginning of year (Predecessor)	—	—	—	—
End of year (Predecessor)	454	—	—	454

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

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

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. 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). In addition, extensions and discoveries, principally in our California properties, most of which was thermal Diatomite, as well as in Utah, contributed approximately 22,362 MBoe to the increase in proved reserves.

Proved reserves increased by approximately 8,305 MBoe to approximately 141,385 MBoe for the year ended December 31, 2017, from 133,080 MBoe for the year ended December 31, 2016. The year ended December 31, 2017, includes approximately 14,878 MBoe of positive revisions of previous estimates due to higher commodity prices. Extensions and discoveries, contributed approximately 41,570 MBoe to the increase in proved reserves, primarily due to the certainty attained in the Company's future commitment to capital as a result of its emergence from bankruptcy allowing inclusion of PUDs previously excluded due to the SEC five-year development limitation on PUDs, as well as from 93 productive wells drilled during the year. Lastly, the Hugoton Disposition and Hill Acquisition had a net negative impact on proved reserves of approximately 36,538 MBoe (negative impact on reserves from the Hugoton Disposition of approximately 60,870 MBoe offset by the positive impact on reserves from the Hill Acquisition of approximately 24,332 MBoe).

Proved reserves decreased by approximately 42,407 MBOE to approximately 133,080 MBOE for the year ended December 31, 2016, from 175,487 MBOE for the year ended December 31, 2015. The year ended December 31, 2016, includes approximately 29,701 MBOE of negative revisions of previous estimates (22,729 MBOE due to asset performance and 6,972 MBOE due to lower commodity prices). In addition, extensions and discoveries, primarily from 23 productive wells drilled during the year, contributed approximately 1,827 MBOE to the increase in proved reserves.

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

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. There are no future income tax expenses for the Predecessor because the Predecessor was not subject to federal income taxes. Limited liability companies are subject to Texas margin tax; however, these amounts were not material. See Note 10 for additional information about income taxes.

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands, except for prices)		
Future cash inflows	$ 8,119,309	$ 5,580,448	$ 3,131,758
Future production costs	(3,357,149)	(2,725,548)	(1,893,608)
Future development costs	(884,055)	(678,312)	(220,374)
Future income taxes[1]	(757,470)	(365,330)	—
Future net cash flows	3,120,635	1,811,258	1,017,776
10% annual discount for estimated timing of cash flows	(1,359,089)	(833,910)	(421,554)
Standardized measure of discounted future net cash flows	$ 1,761,546	$ 977,348	$ 596,222
Representative prices:[2]			
ICE Brent Oil (Bbl)	$ 71.54	$ 54.42	
NYMEX Henry Hub Natural gas (MMBtu)	$ 3.10	$ 2.98	$ 2.48
NYMEX WTI Oil (Bbl)			$ 42.64

(1) Future income taxes 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.

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

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

	Berry Corp. (Successor)		Berry LLC (Predecessor)
	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands)		
Standardized measure—beginning of year	$ 977,348	$ 596,222	$ 995,372
Sales and transfers of oil, natural gas and NGLs produced during the period	(321,148)	(189,355)	(140,688)
Changes in estimated future development costs	35,313	6,399	66,386
Net change in sales and transfer prices and production costs related to future production	818,705	224,064	(242,982)
Extensions, discoveries and improved recovery	363,450	157,717	21,610
Purchase of minerals in place	5,240	317,616	—
Sales of minerals in place	(5,593)	(141,998)	—
Previously estimated development costs incurred during the period	78,803	6,913	—
Net change due to revisions in quantity estimates	(175,947)	124,609	(158,474)
Accretion of discount	111,416	59,622	99,537
Net change in income taxes	(253,176)	(136,810)	—
Changes in production rates and other	127,135	(47,651)	(44,539)
Net increase (decrease)	784,198	381,126	(399,150)
Standardized measure—end of year	$ 1,761,546	$ 977,348	$ 596,222

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.

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, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation 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, 2018. 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, 2018 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

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. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. 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.

There were no changes in the Company's internal control over financial reporting during the fourth quarter of 2018 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 from our definitive Proxy Statement, for the 2019 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2018 where it will appear in the (i) Directors and Executive Officers section, (ii) The Board and Its Committees – Audit Committees, (iii) Other Information section – Section 16(a) Beneficial Ownership Reporting Compliance and (iv) Corporate Governance – Code of Ethics.

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.ir.berrypetroleum.com/corporate-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 from our definitive Proxy Statement, for the 2019 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2018 where it will appear in the Executive Compensation and Other Information section.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information required by this Item 12 is incorporated herein by reference from our definitive Proxy Statement, for the 2019 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2018 where it will appear in the Certain Relationships and Related Party Transactions section.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this Item 13 is incorporated herein by reference from our definitive Proxy Statement, for the 2019 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2018 where it will appear in the (i) Certain Relationships and Related Party Transactions section and (ii) The Board and Its Committees - Director Independence sections.

Item 14. Principal Accounting Fees and Services

The information required by this Item 14 is incorporated herein by reference from our definitive Proxy Statement, for the 2019 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A within 120 days of December 31, 2018 where it will appear in the Proposal No. 2 - Ratification of Independent Registered Public Accounting Firm.

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	Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.2	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Exhibit 3.2 of Form 8-K filed July 30, 2018)
3.3	Second Amended and Restated Bylaws of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.3 of Form 8-K filed July 30, 2018)
3.4	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))
3.5	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))
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
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†	Executive Employment Agreement, dated March 1, 2017, between Berry Petroleum Company, LLC and Arthur "Trem" Smith (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.6†	Executive Employment Agreement, dated June 28, 2017 between Berry Petroleum Company, LLC and Cary D. Baetz (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.7†	Executive Employment Agreement, dated June 28, 2017 between Berry Petroleum Company, LLC and Gary A. Grove (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
10.8†	Amended and Restated Employment Agreement, Arthur "Trem" Smith (incorporated by reference to Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q filed August 23, 2018)
10.9†	Amended and Restated Employment Agreement, Cary D. Baetz (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q filed August 23, 2018)
10.10†	Amended and Restated Employment Agreement, Gary A. Grove (incorporated by reference to Exhibit 10.16 to the Company's Quarterly Report on Form 10-Q filed August 23, 2018)

Exhibit Number	Description
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
10.20†*	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Executive Officers
10.21†*	Berry Petroleum Corporation Form of Restricted Stock Unit Award Agreement for Directors
10.22†*	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Employees other than Executive Officers
10.23†*	Berry Petroleum Corporation Form of Performance-Based Restricted Stock Unit Award Agreement for Executive Officers
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	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)

Exhibit Number	Description
10.30	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 Petroleum Corporation
23.1*	Consent of KPMG LLP
23.2*	Consent of DeGolyer and MacNaughton
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report as of December 31, 2018 of DeGolyer and MacNaughton
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

(*) 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 used in this report, which are commonly used in the oil and natural gas industry:

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

"*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, including restructuring costs and reorganization 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*" is an abbreviation 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.

"*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.

"*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.

"*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.

"*DOGGR*" is an abbreviation for the Division of Oil, Gas, and Geothermal Resources of the California Department of Conservation.

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

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

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

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

"*Estimated ultimate recovery*" or "*EUR*" means the sum of reserves remaining as of a given date and cumulative production as of that date. As used in this report, EUR includes only proved reserves attributable to each location in our reserve report as of December 31, 2017 and is based on our reserve estimates. EUR is shown on a combined basis for oil and natural gas.

"*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.

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

"*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 stimulation*" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure to increase 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.

"*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.

"*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.

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

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

"*MW*" means megawatt.

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

"*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.

"*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.

"*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.

"*Porosity*" means the total pore volume per unit volume of rock.

"*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 stimulation fluid to hold rock open after a hydraulic stimulation 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.

"*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. 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.

"*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.

“*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.

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

“*SEC*” is an abbreviation for the Securities and Exchange Commission.

“*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.

"*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.

"*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 PETROLEUM CORPORATION

Date: March 7, 2019

/s/ A. T. Smith

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
March 7, 2019	/s/ A. T. Smith A. T. "Trem" Smith	President and Chief Executive Officer, and Director (Principal Executive Officer)
March 7, 2019	/s/ Cary Baetz Cary Baetz	Executive Vice President and Chief Financial Officer, and Director (Principal Financial Officer)
March 7, 2019	/s/ M. S. Helm Michael S. Helm	Chief Accounting Officer (Principal Accounting Officer)
March 7, 2019	/s/ E. J. Voiland Eugene J. Voiland	Director
March 7, 2019	/s/ Brent S. Buckley Brent S. Buckley	Director
March 7, 2019	/s/ C K Potter C. Kent Potter	Director
March 7, 2019	/s/ Anne L. Mariucci Anne L. Mariucci	Director
March 7, 2019	Donald L. Paul	Director

DIRECTORS

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

CARY BAETZ
Executive Vice President
& Chief Financial Officer
Berry Petroleum Corporation

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

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

DONALD PAUL (1) (3)
Independent Director
Executive Director of the Energy Institute,
the William M. Keck Chair of Energy Resources &
Research Professor of Engineering at the
University of Southern California

C. KENT POTTER (1C) (3)
Independent Director
Former Executive Vice President
& Chief Financial Officer of
LyondellBasell Industries

EUGENE (GENE) VOILAND (2C) (1)
Independent Director
Former President & Chief Executive Officer
of Aera Energy LLC

EXECUTIVE OFFICERS

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

CARY BAETZ
Executive Vice President
& Chief Financial Officer

GARY GROVE
Executive Vice President
& Chief Operating Officer

KURT NEHER
Executive Vice President,
Business Development

KENDRICK ROYER
Executive Vice President,
General Counsel & Corporate Secretary

GENERAL SHAREHOLDER INFORMATION
Shareholders and members of the investment
community should direct inquiries to:

INVESTOR RELATIONS
Todd Crabtree
Berry Petroleum Corporation
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
United States
Shareholder Services
(718) 921-8200
www.astfinancial.com

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

BRY
Nasdaq Listed

FORM 10-K
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.

DIVIDEND PAYMENT DATES
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/us/en/home

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

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 and meet working capital requirements; price and availability of natural gas; ability to hedge price risk; impact of governmental regulations, and of current, pending or future legislation; proved reserves estimation uncertainties; ability to replace our reserves; availability of permits; drilling risk; 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”.

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Berry Petroleum Corporation

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