EP Energy Corp
Form 10-K
March 18, 2019
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
(Mark One)
x 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
o 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 001-36253

EP Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware	46-3472728
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1001 Louisiana Street Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 997-1200
Internet Website: www.epenergy.com
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Class A Common Stock, par value $0.01 per share	New York Stock Exchange

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 o No x.
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 o No x.
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 x No o.
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 during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No o.
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. x

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

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company x
Emerging Growth Company o	

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. o

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

Aggregate market value of the Company’s common stock held by non-affiliates of the registrant as of June 29, 2018, was $131,502,027 based on the closing sale price on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date.

Class A Common Stock, par value $0.01 per share. Shares outstanding as of February 28, 2019: 256,236,218

Class B Common Stock, par value $0.01 per share. Shares outstanding as of February 28, 2019: 237,256

Documents Incorporated by Reference: Portions of the definitive proxy statement for the 2019 Annual Meeting of Stockholders of EP Energy Corporation are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Below is a list of terms that are common to our industry and used throughout this document:

/d	=per day
Bbl	=barrel
Bcf	=billion cubic feet
Boe	=barrel of oil equivalent
LLS	=light Louisiana sweet crude oil
MBoe	=thousand barrels of oil equivalent
MBbls	=thousand barrels
Mcf	=thousand cubic feet
MMBtu	=million British thermal units
MMBoe	=million barrels of oil equivalent
MMBbls	=million barrels
MMcf	=million cubic feet
MMGal	=million gallons
Mt. Belvieu	=natural gas liquids pricing index at the processing and storage hub in Mont Belvieu, TX
NGLs	=natural gas liquids
NYMEX	=New York Mercantile Exchange
TBtu	=trillion British thermal units
Waha	=natural gas pricing index at the Waha header system/vicinity in the Permian basin in West Texas
WTI	=West Texas intermediate

When we refer to oil and natural gas in “equivalents,” we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. Equivalent volumes are computed with natural gas converted to barrels at a ratio of six Mcf to one Bbl. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to “us”, “we”, “our”, “ours”, “the Company”, or “EP Energy”, we are describing EP Energy Corporation and/or subsidiaries.

All references to “common stock” herein refer to Class A common stock.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that involve risks and uncertainties, many of which are beyond our control. These forward-looking statements are based on assumptions or beliefs that we believe to be reasonable; however, assumed facts almost always vary from the actual results and such variances can be material. Where we express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the stated expectation or belief will occur. The words “believe”, “expect”, “estimate”, “anticipate”, "plan", “intend”, "could" and “should” and similar expressions will generally ide forward-looking statements. All of our forward-looking statements are expressly qualified by these and the other cautionary statements in this Annual Report, including those set forth in Item 1A, "Risk Factors". Important factors that could cause our actual results to differ materially from the expectations reflected in our forward-looking statements include, among others:

- the volatility of and potential for sustained low oil, natural gas, and NGLs prices;
- the supply and demand for oil, natural gas and NGLs;
- changes in commodity prices and basis differentials for oil and natural gas;
- our ability to meet production volume targets;
- the uncertainty of estimating proved reserves and unproved resources;
- our ability to develop proved undeveloped reserves;
- the future level of operating and capital costs;
- the availability and cost of financing to fund future exploration and production operations;
- the success of drilling programs with regard to proved undeveloped reserves and unproved resources;
- our ability to comply with the covenants in various financing documents;
- our ability to generate sufficient cash flow to meet our debt obligations and commitments;
- the possibility that we may not be able to continue as a going concern beginning in May 2020 if we are not successful in obtaining the necessary additional liquidity and/or if commodity prices do not appreciably increase;
- our limited ability to borrow under existing debt agreements to fund our operations;
- our ability to obtain necessary governmental approvals for proposed exploration and production projects and to successfully construct and operate such projects;
- actions by credit rating agencies, including potential downgrades;
- credit and performance risks of our lenders, trading counterparties, customers, vendors, suppliers and third party operators;
- general economic and weather conditions in geographic regions or markets we serve, or where operations are located, including the risk of a global recession and negative impact on demand for oil and/or natural gas;
- the uncertainties associated with governmental regulation, including any potential changes in federal and state tax laws and regulations;
- competition; and
- the other factors described under Item 1A, “Risk Factors,” on pages 14 through 33 of this Annual Report on Form 10-K, and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by these forward-looking statements may not occur, and, if any of such events do occur, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of these forward-looking statements. These forward-looking statements speak only as of the date made, and we undertake no obligation, other than as required by

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applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

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PART I

ITEM 1.   BUSINESS

Overview

EP Energy Corporation (EP Energy), a Delaware corporation formed in 2013, is an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. Our strategy is to invest in opportunities that provide the highest return across our asset base, continually seek out operating and capital efficiencies, effectively manage costs, and identify accretive acquisition opportunities and divestitures, all with the objective of enhancing our portfolio, growing asset value, improving cash flow and increasing financial flexibility.

We operate through a diverse base of producing assets and are focused on the development of our drilling inventory located in three areas: the Eagle Ford Shale in South Texas, Northeastern Utah (NEU), formerly Altamont, in the Uinta basin, and the Permian basin in West Texas. As of December 31, 2018, we had proved reserves of 324.5 MMBoe (52% oil and 70% liquids) and for the year ended December 31, 2018, we had average net daily production of 80,654 Boe/d (57% oil and 74% liquids).

Each of our areas is characterized by a long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in each area, representing approximately 457,000 net (596,000 gross) acres in total.

In addition to opportunities in our current portfolio, strategic acquisitions of leasehold acreage or acquisitions of producing assets can allow us to leverage existing expertise in our operating areas, balance our exposure to regions, basins and commodities, help us achieve or enhance risk-adjusted returns competitive with those available in our existing programs and increase our reserves. We also continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term objectives.

Liquidity Concerns

In May 2020, $182 million of our senior unsecured notes will mature. Based on our current forecasted EBITDAX (assuming $55/barrel of oil), cash on hand, and remaining capacity under our reserve-based revolving credit facility (the RBL Facility), we project that as of May 2020, we will not have sufficient liquidity available to repay these notes and meet our working capital needs and/or fund our planned capital expenditures. In order to address this projected shortfall in liquidity, we are evaluating certain other sources of incremental liquidity, including additional debt issuances or refinancings and asset sales.

If we are not successful in obtaining the necessary additional liquidity, whether through executing one or more of these potential actions or otherwise, and/or if commodity prices do not appreciably increase prior to the filing date of our Quarterly Report on Form 10-Q for the period ending March 31, 2019, we would expect to disclose in that Quarterly Report that, in the absence of executing on these potential actions or commodity prices appreciably increasing, there would be substantial doubt that we would be able to continue as a going concern beginning in May 2020. In addition, should we be required to include a going concern disclosure in our year-end audited financial statements (in the absence of a waiver or other suitable relief), the disclosure would result in an event of default under the RBL Facility, after which the lenders thereunder could accelerate the outstanding indebtedness. An event of default under our RBL Facility could trigger cross-defaults under our other debt agreements, including our senior secured term loan and our senior secured and unsecured notes, which could also result in the acceleration of those obligations by the lenders thereunder. Even if we are able to implement such strategic alternatives, they may be insufficient to meet our debt and other obligations. Furthermore, such strategic alternatives may adversely affect our creditors or our existing stockholders, potentially resulting in the loss of all or substantially all of their investment in us.

Reserves Summary

The following table provides a summary of oil, natural gas and NGLs reserves as of December 31, 2018 and production data for the year ended December 31, 2018 for each of our areas of operation.

	Estimated Proved Reserves[1]						
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)[2]	Average Net Daily Production (MBoe/d)
Eagle Ford Shale	83.8	27.7	166.0	139.1	80 %	67 %	37.1
Northeastern Utah	65.9	—	186.8	97.0	68 %	54 %	17.1
Permian	19.0	32.4	221.7	88.4	58 %	100 %	26.5
Total	168.7	60.1	574.5	324.5	70 %	72 %	80.7

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(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $65.56 per Bbl (WTI), $3.10 per MMBtu (Henry Hub) and $23.60 per Bbl of NGLs.

(2) Includes 7 MMBoe of proved developed non-producing reserves representing 2% of total net proved reserves at December 31, 2018.

Approximately 226 MMBoe, or 70%, of our total proved reserves are proved developed producing assets, which generated average production of 80.7 MBoe/d in 2018 from approximately 1,744 wells. As of December 31, 2018, we had approximately 169 MMBbls of proved oil reserves, 60 MMBbls of proved NGLs reserves and 575 Bcf of proved natural gas reserves, representing 52%, 18% and 30%, respectively, of our total proved reserves. For both of the years ended December 31, 2018 and 2017, 74% of our production was related to oil and NGLs.

As of December 31, 2018, we operated 95% of our producing wells. This control provides us with flexibility around the amount and timing of capital spending and has allowed us to improve our capital and operating efficiencies. We also employ a function-based organizational structure to accelerate knowledge sharing, innovation, evaluation and target efficiencies across our drilling, completion and operating activities across our operating areas. In 2018, we completed 136 wells and as of December 31, 2018, we had a total of 29 wells drilled, but not completed across our programs.

Our Properties

Eagle Ford Shale. The Eagle Ford Shale, located in South Texas, is one of the premier unconventional oil plays in the United States. We were an early entrant into this play in late 2008, and since that time have acquired a leasehold position in the core of the oil window, primarily in La Salle County. The Eagle Ford formation in La Salle County has up to 125 feet of net thickness (165 feet gross). Due to its high carbonate content, the formation is also very brittle, and exhibits high productivity when fractured. During 2018, we (i) completed acquisitions expanding our Eagle Ford acreage position by approximately 30 percent in La Salle County, for approximately $277 million and (ii) invested $425 million in capital (excluding approximately $315 million in acquisition capital). As of December 31, 2018, we had 119,705 net (130,293 gross) acres in the Eagle Ford.

During 2018, we operated an average of three drilling rigs and as of December 31, 2018, we had 804 net producing wells (800 net operated wells) in this program. We are currently running three rigs in the Eagle Ford. For the year ended December 31, 2018, our average net daily production was 37,067 Boe/d, representing an increase of 4% over the same period in 2017 due to improved well performance and additional capital allocated to this program in 2018.

Northeastern Utah. The Northeastern Utah asset, formerly Altamont, is located in Duchesne and Uinta counties in the Uinta basin. The Uinta basin is characterized by naturally fractured, tight-oil sands and carbonates with multiple pay zones. Our operations are primarily focused on developing the NEU Complex, which is comprised of the Altamont, Bluebell and Cedar Rim fields. The NEU Complex has a gross pay interval thickness of over 4,300 feet and we believe the Wasatch and Green River formations are ideal targets for horizontal drilling and modern fracture stimulation techniques. Our commingled production is from over 1,500 feet of net stimulated rock. Historically, our activity has been focused on the development of our vertical inventory on 80-acre and 160-acre spacing; however, we also recently completed our first two horizontal wells with lateral lengths between 7,900 and 9,800 feet. Industry activity has focused on horizontal drilling in the Wasatch and Green River formations testing tight carbonate and sand intervals and has also piloted 80-acre vertical downspacing in these formations. Due to the largely held-by-production nature of our acreage position, if horizontal drilling continues to be successful, it will result in additional opportunities that could be added to our inventory of drilling locations.

We are subject to a drilling joint venture to accelerate and fund future oil and natural gas development in NEU. Under the joint venture, our partner is participating in the development of 60 wells and will provide a capital carry in exchange for a 50 percent working interest in the joint venture wells. As of December 31, 2018, we have drilled and completed 43 wells under the joint venture agreement.

During 2018, we (i) completed the sale of certain assets in NEU for approximately $177 million representing approximately 13 percent of our NEU acreage position and (ii) invested $120 million in capital in NEU (excluding approximately $2 million in acquisition capital). As of December 31, 2018, we had 155,314 net (282,885 gross) acres in NEU.

During 2018, we operated an average of two drilling rigs in NEU. As of December 31, 2018, we had 348 net producing wells (342 net operated wells) and are currently running one rig in this program. For the year ended December 31, 2018, our average net daily production was 17,051 Boe/d, representing a decrease of 4% over 2017 due to the sale of certain assets in NEU during the first quarter of 2018 as further discussed in Part II, Item 8, "Financial Statements and Supplementary Data", Note 2.

Permian. The Permian basin is characterized by numerous stacked oil reservoirs (including the Wolfcamp A, B and C zones) that provide multiple targets for horizontal drilling. In 2009 and 2010, we leased 138,130 net (138,469 gross) acres on the University of Texas Land System in the Permian basin, located primarily in Reagan, Crockett, Upton and Irion counties. In

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2014, we acquired approximately 37,000 net acres in the Southern Midland basin. As of December 31, 2018, we had 182,114 net (183,031 gross) acres in the Permian.

We are party to a Consolidated Drilling and Development Unit Agreement with the University of Texas Land System in the Permian basin to provide flexibility to extend the time frame to hold our acreage through 2021, with an annual well completion requirement of 55 wells per year through 2020. For the years ended 2016 and 2017, we met our annual well completion requirement; however, we failed to meet this requirement in 2018. To the extent that we meet our annual well completion requirement, the wells completed during that year qualify for a variable royalty, which is determined using a rolling average six month price with royalty rates of 12.5% at an average price of $50 per Bbl (WTI) and below; 18.75% at an average price of $50.01 to $60 per Bbl (WTI); 25% at an average price of $60.01 to $80 per Bbl (WTI); and 28% above $80 per Bbl (WTI). Should we not meet our annual well completion requirement in a given year, the wells completed during that given year will not qualify for the variable royalty and instead be subject to a 25.00% royalty rate.

In 2017, we entered into a drilling joint venture to accelerate and fund future oil and natural gas development in the Permian basin. Under the joint venture, our partner had the option to participate in the development of up to 150 wells in two separate 75 well tranches primarily in Reagan and Crockett counties. In April 2018, we amended this drilling joint venture agreement to direct the development area for the second tranche from the Permian to the Eagle Ford with anticipated joint venture investment in the Eagle Ford of $225 million. The first wells under the amended agreement began producing in the third quarter of 2018. We retain operational control of the joint venture assets. For a further discussion of this joint venture, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 11.

During 2018, we invested $99 million in capital (excluding approximately $23 million in capital adjustments under a joint venture agreement) in the Permian and operated an average of less than one drilling rig. As of December 31, 2018, we had 353 net producing wells (350 net operated wells). We are currently not running any rigs in this program. For the year ended December 31, 2018, our average net daily production was 26,465 Boe/d, representing a decrease of 8% over 2017, reflecting the slower pace of development from reduced capital spending in 2018.

The following table provides a summary of acreage and gross operated wells completed in each of the following areas as of December 31, 2018:

	Acres		Gross Operated Wells Completed (#)
	Gross	Net	
Eagle Ford Shale	130,293	119,705	85
Northeastern Utah	282,885	155,314	27
Permian	183,031	182,114	24
Total	596,209	457,133	136

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Oil and Natural Gas Properties

Oil, Natural Gas and NGLs Reserves and Production

Proved Reserves

The proved oil and gas reserve estimates as of December 31, 2018 presented in the table below have been prepared by Ryder Scott Company L.P. (Ryder Scott), our independent third party reserve engineers. The reserve data represents only estimates, which are often different from the quantities of oil and natural gas that are ultimately recovered, and is consistent with estimates of reserves filed with other federal agencies except for differences of less than 5% resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. The risks and uncertainties associated with estimating proved oil and natural gas reserves are discussed further in Item 1A, "Risk Factors". Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2018.

	Net Proved Reserves(1)				
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Percent (%)
Reserves by Classification					
Proved Developed					
Eagle Ford Shale	57.7	17.6	105.4	92.8	29 %
Northeastern Utah	34.5	—	107.3	52.4	16 %
Permian	19.0	32.4	221.7	88.4	27 %
Total Proved Developed(2)	111.2	50.0	434.4	233.6	72 %
Proved Undeveloped					
Eagle Ford Shale	26.1	10.1	60.6	46.3	14 %
Northeastern Utah	31.4	—	79.5	44.6	14 %
Total Proved Undeveloped	57.5	10.1	140.1	90.9	28 %
Total Proved Reserves	168.7	60.1	574.5	324.5	100 %

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $65.56 per Bbl (WTI), $3.10 per MMBtu (Henry Hub) and $23.60 per Bbl of NGLs. For a further discussion of our proved reserves and changes therein, see Part II, Item 8, "Financial Statements and Supplementary Data", under the heading Supplemental Oil and Natural Gas Operations.

(2) Includes 226 MMBoe of proved developed producing reserves representing 70% of total net proved reserves and 7 MMBoe of proved developed non-producing reserves representing 2% of total net proved reserves at December 31, 2018.

The table below presents net proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2018.

	Net Proved Reserves (MMBoe)
As Reported	324.5
10 percent increase in commodity prices	330.4
10 percent decrease in commodity prices	316.5

The sensitivities in the table above were based on the average first day of the month spot price for the preceding 12-month period of $65.56 per barrel of oil (WTI), $3.10 per MMBtu of natural gas (Henry Hub) and $23.60 per Bbl of NGLs used to determine net proved reserves at December 31, 2018.

Ryder Scott prepared 100% (by volume) of our total net proved developed and undeveloped (PUD) reserves on a barrel of oil equivalent basis. The overall procedures and methodologies utilized by Ryder Scott in evaluating and preparing estimates of our net proved reserves as of December 31, 2018 complied with current SEC regulations. Ryder Scott's report is included as an exhibit to this Annual Report on Form 10-K.

The technical person at Ryder Scott primarily responsible for overseeing the reserves evaluation and preparation has a B.S. degree in chemical engineering. He is a Licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has more than 15 years of experience in petroleum reserves evaluation.

The significant assumptions used in the proved oil and gas reserve estimates prepared by Ryder Scott were also assessed by our internal reserve team. Our internal reserve team is comprised of a technical staff of engineers and geoscientists

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that perform technical analysis of each undeveloped location. The staff uses industry accepted practices to estimate, with reasonable certainty, the economically producible oil and natural gas. The practices for estimating hydrocarbons in place include, but are not limited to, mapping, seismic interpretation of two-dimensional and/or three-dimensional data, core analysis, mechanical properties of formations, thermal maturity, well logs of existing penetrations, correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

Our primary internal technical person in charge of overseeing our reserves estimates has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He leads the reservoir engineering evaluation and strategic planning groups of the company. In this capacity, he oversees the reserve reporting and technical support groups. He has eight years of industry experience in various engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates”.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as they are produced. Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of PUD reserves and proved non-producing reserves are inherently subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, "Financial Statements and Supplementary Data", under the heading Supplemental Oil and Natural Gas Operations.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2018, we have 91 MMBoe of PUD reserves in the Eagle Ford and NEU. Estimated capital expenditures to develop our PUD reserves (convert PUD reserves to proved developed reserves) are based upon a long-range plan approved by our management team and reviewed with the Board of Directors. All PUD locations are surrounded by producing properties, and a majority of our PUDs directly offset a producing property. Where we have recorded PUDs beyond one location away from a producing property, reasonable certainty of economic producibility has been established by reliable technology in our areas, including field tests that demonstrate consistent and repeatable results within the formation being evaluated.

Our PUD reserves at December 31, 2018 reflect the effects of adjusting our PUD bookings methodology from a five-year to a three-year timeframe as a result of (i) the current economic price environment, (ii) a lower projected capital budget in 2019, and (iii) our available liquidity and access to the capital markets. Given our current financial situation with limited available liquidity, our PUD reserves of 91 MMboe at December 31, 2018 reflect only a three-year development timframe. The table below includes 64 MMBoe (29 MMBoe to extensions and discoveries, 4 MMBoe to acquisitions, and 31 MMBoe to revisions other than price) of negative adjustments in 2018 when calculating each respective category as a result of determining our PUDs using a three-year timeframe instead of a five-year timeframe.

The following table summarizes our changes in PUDs for the years ended December 31, 2017 and December 31, 2018, respectively (in MMBoe):

Balance, December 31, 2016	227.8
Extensions and discoveries	15.1
Revisions due to prices	1.4
Revisions other than prices	(23.4)
Transfers to proved developed	(30.7)
Divestitures	(16.4)
Balance, December 31, 2017	173.8
Extensions and discoveries	—

Acquisitions	12.5
Revisions due to prices	0.1
Revisions other than prices	(65.6)
Transfers to proved developed	(22.6)
Divestitures	(7.3)
Balance, December 31, 2018	90.9

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Revisions due to prices represent PUD revisions due to increases or decreases in commodity prices (using SEC 12-month average pricing). For the year ended December 31, 2018, revisions to PUDs other than prices primarily include negative revisions of 74 MMBoe due to a reallocation of capital from the Permian to other development areas and positive revisions of 12 MMBoe associated with increased drilling activity in the Eagle Ford and NEU.

Extensions and discoveries in 2017 are primarily related to drilling activities across all areas. For the year ended December 31, 2017, revisions to PUDs other than prices include, among other items, negative revisions of 23 MMBoe due to a reallocation of capital in our development areas; a negative PUD ownership reversion of 10 MMBoe as a result of our variable royalty agreement in the Permian; a positive revision of 10 MMBoe from improved operating expenses and planned development of longer lateral PUDs; and the divestiture of 16 MMBoe is related to drilling joint ventures we entered into during 2017.

The year ended December 31, 2018 includes 4 MMBoe of PUDs that have a positive undiscounted value, but a negative value when discounted at 10 percent. The majority of these PUDs become negative at a 10 percent discount rate due to the historically lower resource potential in this area. However, recent 2018 results prove this area to be much more prospective than currently modeled. We expect these wells to be economic with current results and assumptions.

During 2018, 2017 and 2016 we spent approximately $444 million, $377 million and $281 million, respectively, to convert approximately 13% or 23 MMBoe, 13% or 31 MMBoe and 9% or 25 MMBoe, respectively, of our prior year-end PUD reserves to proved developed reserves. In 2019, 2020 and 2021 we estimate we will spend approximately $280 million, $564 million and $607 million to develop our PUD reserves, respectively, based on our December 31, 2018 reserve report. At this level of spending from 2019 through 2021, and based on our current liquidity projections and ability to fund capital expenditures in our long-range plan, and expected access to capital market transactions, we have the intent to develop 100% of our existing PUD reserves within a three-year period. The actual amount and timing of our forecasted expenditures will depend on a number of factors, including actual drilling results, oilfield service costs, technology, acreage position, availability of capital and future commodity prices, which in the future could be lower than those in our projected long-range plan.

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2018, (ii) our interest in oil and natural gas wells at December 31, 2018 and (iii) our development wells completed during the years 2016 through 2018. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

Acreage

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Eagle Ford Shale	46,367	43,718	83,926	75,987	130,293	119,705
Northeastern Utah	144,323	103,752	138,562	51,562	282,885	155,314
Permian	25,881	22,725	157,150	159,389	183,031	182,114
Other	70,501	5,924	214,085	96,535	284,586	102,459
Total Acreage	287,072	176,119	593,723	383,473	880,795	559,592

(1) Gross interest reflects the total acreage we participate in regardless of our ownership interest in the acreage.
(2) Net interest is the aggregate of the fractional working interests that we have in the gross acreage.

Our net developed acreage is concentrated in Texas (40%) and Utah (59%). Our net undeveloped acreage is concentrated in Texas (63%), Utah (14%), West Virginia (11%) and Wyoming (9%). Approximately 4%, 2% and 5% of our net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2019, 2020 and 2021, respectively. We employ various techniques to manage the expiration of leases, including drilling the acreage ourselves prior to lease expiration, entering into farm-out or joint development agreements with other operators or extending lease terms.

Productive Wells

	Oil		Wells In Progress at December 31, 2018(1)	
	Gross(2)	Net(3)(4)	Gross(2)	Net(3)
Eagle Ford Shale	896	804	29	27
Northeastern Utah	449	348	7	6
Permian	399	353	3	3
Total Productive Wells	1,744	1,505	39	36

(1) Comprised of wells that were spud as of December 31, 2018 and have not been completed.
(2) Gross interest reflects the total wells we participated in, regardless of our ownership interest.
(3) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.
(4) At December 31, 2018, we operated 1,492 of the 1,505 net productive wells.

Wells Completed(1)

	Net Development(2)		
	2018	2017	2016
Total Productive Wells Completed	91	106	94

(1) No dry wells or exploratory wells were drilled or completed during the years 2016 through 2018.
(2) Net development is the aggregate of the fractional working interests that we have in the gross wells completed.

The performance above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells completed and the amount of oil and natural gas that may ultimately be recovered.

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Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, and prices and costs per unit for each of the three years ended December 31:

	2018	2017	2016
Volumes:			
Total Net Production Volumes			
Oil (MBbls)	16,726	16,833	17,061
Natural Gas (MMcf)(1)	44,913	46,356	57,799
NGLs (MBbls)	5,227	5,465	5,383
Total Equivalent Volumes (MBoe)	29,439	30,024	32,077
MBoe/d(1)	80.7	82.3	87.6
Net Production Volumes by Area			
Eagle Ford Shale			
Oil (MBbls)	9,137	8,168	9,679
Natural Gas (MMcf)	12,915	14,114	18,442
NGLs (MBbls)	2,240	2,498	3,164
Total Eagle Ford Shale (MBoe)	13,530	13,018	15,916
Northeastern Utah			
Oil (MBbls)	4,269	4,493	4,224
Natural Gas (MMcf)	11,708	11,992	10,851
NGLs (MBbls)	4	4	6
Total Northeastern Utah (MBoe)	6,224	6,495	6,039
Permian			
Oil (MBbls)	3,318	4,168	3,155
Natural Gas (MMcf)	20,169	20,117	14,823
NGLs (MBbls)	2,980	2,959	2,210
Total Permian (MBoe)	9,660	10,480	7,836
Other			
Oil (MBbls)	2	4	3
Natural Gas (MMcf)(1)	121	133	13,684
NGLs (MBbls)	3	5	2
Total Other (MBoe)(1)	25	31	2,286
Prices and Costs per Unit:(2)			
Oil Average Realized Sales Price ($/Bbl)			
Physical Sales	$62.34	$48.23	$38.24
Including Financial Derivatives(3)	$60.37	$53.50	$74.88
Natural Gas Average Realized Sales Price ($/Mcf)			
Physical Sales	$1.66	$2.32	$1.95
Including Financial Derivatives(3)	$1.96	$2.47	$2.19
NGLs Average Realized Sales Price ($/Bbl)			
Physical Sales	$22.88	$18.87	$12.02
Including Financial Derivatives(3)	$21.79	$18.46	$12.19
Average Transportation Costs			
Oil ($/Bbl)	$1.80	$1.86	$1.88
Natural Gas ($/Mcf)	$1.56	$1.79	$1.32
NGLs ($/Bbl)	$0.08	$0.15	$0.22
Average Lease Operating Expenses ($/Boe)(4)	$5.35	$5.42	$4.97

Average Production Taxes ($/Boe)	$2.47	$2.02	$1.37

(1) Natural gas volumes in 2016 include 13,556 MMcf or 6.2 MBoe/d from the Haynesville Shale which was sold in May 2016.

(2) Oil prices for the years ended December 31, 2018 and 2016 reflect operating revenues for oil reduced by $3 million and $1 million, respectively, for oil purchases associated with managing our physical oil sales. For the year ended December 31, 2017, there were no oil purchases associated with managing our physical oil sales. Natural gas prices for the years ended December 31, 2018, 2017 and 2016 reflect operating revenues for natural gas reduced by less than $1 million, $2 million and $9 million, respectively, for natural gas purchases associated with managing our physical sales.

(3) Includes actual cash settlements related to financial derivatives.

(4) Includes approximately $0.07 per Boe of adjustments under a joint venture agreement for the year ended December 31, 2018.

Acquisition, Development and Exploration Expenditures

See Part II, Item 8, "Financial Statements and Supplementary Data" under the heading Supplemental Oil and Natural Gas Operations in the Total Costs Incurred table for details on our acquisition, development and exploration expenditures.

Transportation, Markets and Customers

Our marketing strategy seeks to ensure maximum deliverability of our physical production at the maximum realized prices. We leverage knowledge of markets and transportation infrastructure to enter into beneficial downstream processing, treating and marketing contracts. We primarily sell our domestic oil and natural gas production to third parties at spot market prices, while we sell our NGLs at market prices under monthly or long-term contracts. We typically sell our oil production to a relatively small number of creditworthy counterparties, as is customary in the industry. For the year ended December 31, 2018, nine purchasers accounted for approximately 90% of our oil revenues. The top two purchasers are: Shell Trading U.S. Co. (an affiliate of Shell Oil Company) and Flint Hills Resources, LP (an affiliate of Koch Industries), which together accounted for approximately 41% of our oil revenues. Across all of our areas, we maintain adequate gathering, treating, processing and transportation capacity, as well as downstream sales arrangements, to accommodate our production volumes.

In our Eagle Ford Shale area, we are connected to the Camino Real oil gathering system and to the NuStar Energy system. The vast majority of our oil production flows on Camino Real, a 68-mile long pipeline with over 110,000 Bbls/d of capacity and a gravity bank that allows for oil blending to maintain attractive API levels. We have 80,000 Bbls/d of firm capacity on this oil system, of which we utilized an average of 35% during December 2018 and 36% on average for the year. The system delivers oil to the Storey Oil Terminal east of Cotulla, Texas, southeast of Gardendale, Texas. From the Storey Oil Terminal, oil can be pumped into Harvest's Arrowhead #1 and/or #2 pipelines, as well as the Plains All American Pipeline connection to the Gardendale Hub. Oil can also be loaded into trucks out of the Storey Oil Terminal or out of the numerous central tank batteries throughout our field, providing additional deliverability, reliability and flexibility. We currently market our oil either at the Storey Oil Terminal, Gardendale or at our central tank batteries under a combination of short and long-term contracts, ranging from monthly deals to multi-year term sales. With adequate takeaway capacity in the region and close proximity to the Gulf Coast refining complex, we believe we have sufficient capacity on our contracts and do not anticipate any issues with marketing and delivering volumes from the Eagle Ford Shale.

Our Eagle Ford natural gas production flows on either the Camino Real gas gathering system or the Frio LaSalle Pipeline system with the majority flowing on the Camino Real gas gathering system. The Camino Real gas gathering system receives high-pressure, unprocessed wellhead gas into an 83-mile pipeline with capacity up to 150 MMcf/d. The gas is then redelivered into interconnects with ETC Texas Pipeline LTD, Enterprise Hydrocarbons LP, Regency Energy Partners LP and Eagle Ford Gathering LLC. We currently have 125 MMcf/d of firm transportation capacity on Camino Real, of which we used an average of 56% during December 2018 and 45% on average for the year, and we have additional capacity available as needed. We have firm gas gathering, processing and transportation agreements on three of the interconnected gas pipelines downstream of the Camino Real system, with a minimum capacity of approximately 100 MMBtu/d and rights to increase firm capacity as necessary. In addition, gas produced from our northwest acreage position within the Eagle Ford area is connected to the Frio LaSalle Pipeline system, which provides access to firm H_2S treating and processing. Frio LaSalle can either return gas to the Camino Real system or, after processing, deliver to various Texas intrastate pipelines and a mix of interstates, such as Texas Eastern Transmission, Tennessee Gas Pipeline, and Transco. We market our physical gas to various purchasers at spot market prices.

In NEU, the wax crude we produce is sold at the wellhead to multiple purchasers who transport the oil via truck to downstream refineries. We sell most of the oil we produce in the basin to Salt Lake City refineries under long-term sales agreements that accommodate our production forecasts. Our produced natural gas is gathered and processed at the Altamont plant, a third-party-owned processing facility, under a long-term sales agreement that provides for residue gas return for operational use.

In the Permian basin, we continue to leverage significant legacy gathering, processing and transportation infrastructure. For natural gas, we are connected to the West Texas Gas (WTG), DCP Midstream LP, Targa Pipeline

Mid-Continent WestTex LLC and Cogent Midstream, LLC gathering systems, and we process a majority of our gas at the WTG Benedum & Sonora gas plants. We receive Waha pricing for our natural gas and Mt. Belvieu pricing for our NGLs. Our crude oil production facilities are connected to a third party oil gathering system that delivers to a Plains All American Pipeline at Owens Station in Reagan County, Texas, the Centurion Cline Shale Pipeline at Barnhart in Irion County, Texas and to the Magellan Longhorn pipeline in Crockett County, Texas. We sell our pipeline delivered crude to multiple purchasers under both short and long-term contracts at WTI-based pricing. We also maintain the capability to truck crude oil to those same purchasers under similarly-priced contracts to provide additional flow assurance. Given current Permian basin takeaway capacity, we anticipate no limitations moving physical crude oil to market.

While most of our physical production is priced off spot market indices, we actively manage the volatility of spot market pricing through our risk management program. We enter into financial derivatives contracts on our oil, natural gas and a portion of our NGLs production to stabilize our cash flows, reduce the risk of downward commodity price movements and protect the economic assumptions associated with our capital investment program. We employ a disciplined risk management program that utilizes risk control processes. For a further discussion of these risk management activities and derivative contracts, see Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Competitors

The exploration and production business is highly competitive in the search for and acquisition of additional oil and natural gas reserves and in the sale of oil, natural gas and NGLs. Our competitors include major and intermediate sized oil and natural gas companies, independent oil and natural gas operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include financial resources, price and contract terms, our ability to access drilling, completion and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in this business will be dependent on our ability to find and/or fund the acquisition and development of additional reserves at costs that yield acceptable returns on the capital invested.

Use of 3-D Seismic Data

Within our areas we have an inventory of approximately 1,473 square miles of 3-D seismic data providing approximately 49% coverage of our leased acreage in those areas. We use our 3-D seismic data to improve our geologic models for each area. In the Eagle Ford and the Permian, detailed maps of structural features (e.g., natural fractures, faulting and stratigraphic discontinuities) are used to position well bore laterals to optimally exploit oil bearing zones and navigate drilling hazards. In NEU, data analytics are run using 3-D seismic attributes to identify ideal locations in the reservoir and estimate resource distribution. Seismic data sets are continually updated to keep pace with technological advancements in seismic processing.

Regulatory Environment

Our oil and natural gas exploration and production activities are regulated at the federal, state and local levels in the United States. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to various governmental safety and environmental regulations in the jurisdictions in which we operate.

Our operations under federal oil and natural gas leases are regulated by the statutes and regulations of the Department of the Interior (DOI) that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Office of Natural Resources Revenue within the DOI, which has promulgated valuation guidelines for the payment of royalties by producers. These laws and regulations affect the construction and operation of facilities, water disposal rights and drilling operations, among other items. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

Hydraulic Fracturing. Hydraulic fracturing is a process of pumping fluid and proppant (usually sand) under high pressure into deep underground geologic formations that contain recoverable hydrocarbons. These hydrocarbon formations are typically thousands of feet below the surface. The hydraulic fracturing process creates small fractures in the hydrocarbon formation. These fractures allow natural gas and oil to move more freely through the formation to the well and finally to the surface production facilities. We use hydraulic fracturing to maximize productivity of our oil and natural gas wells in our areas, and our proved undeveloped oil and natural gas reserves will be developed using hydraulic fracturing. For the year ended December 31, 2018, we incurred costs of approximately $282 million associated with hydraulic fracturing.

Hydraulic fracturing fluid is typically composed of over 99% water and proppant. The other 1% or less of the fluid is composed of additives that may contain acid, friction reducer, surfactant, gelling agent and scale inhibitor. We retain service companies to conduct such operations and we have worked with several service companies to evaluate, test and, where appropriate, modify our fluid design to reduce the use of chemicals in our fracturing fluid. We have worked closely with our service companies to provide voluntary and regulatory disclosure of our hydraulic fracturing fluids.

In order to protect surface and groundwater quality during the drilling and completion phases of our operations, we follow applicable industry practices and legal requirements of the applicable state oil and natural gas commissions with regard to well design, including requirements associated with casing steel strength, cement strength and slurry design. Our activities in the field are monitored by state and federal regulators. Key aspects of our field protection measures include: (i) pressure testing well construction and integrity, (ii) casing and cementing practices to ensure pressure management and separation of hydrocarbons from groundwater, and (iii) public disclosure of the contents of hydraulic fracturing fluids.

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In addition to these measures, our drilling, casing and cementing procedures are designed to prevent fluid migration and typically include some or all of the following:

- Our drilling process executes several repeated cycles conducted in sequence—drill, set casing, cement casing and then test casing and cement for integrity before proceeding to the next drilling interval.
- Conductor casing is drilled and cemented or driven in place. This string serves as the structural foundation for the well. Conductor casing is not necessary or required for all wells.
- Surface casing is set and is cemented in place. Surface casing is set on all wells. The purpose of the surface casing is to isolate and protect Underground Sources of Drinking Water (USDW) as identified by federal and state regulatory bodies. The surface casing and cement isolates wellbore materials from any potential contact with USDWs.
- Intermediate casing is set through the surface casing to a depth necessary to isolate abnormally pressured subsurface formations from normally pressured formations. Intermediate casing is not necessary or required for all wells. Our standard practices include cementing above any hydrocarbon bearing zone and performing casing pressure tests to verify the integrity of the casing and cement.
- Production casing is set through the surface and intermediate casing through the depth of the targeted producing formation. Our standard practices include pumping cement above the confining structure of the target zone and performing casing pressure tests and other tests to verify the integrity of the casing and cement. If any problems are detected, then appropriate remedial action is taken.
- With the casing set and cemented, a barrier of steel and cement is in place that is designed to isolate the wellbore from surrounding geologic formations. This barrier as designed mitigates against the risk of drilling or fracturing fluids entering potential sources of drinking water.

In addition to the required use of casing and cement in the well construction, we follow additional regulatory requirements and industry operating practices. These typically include pressure testing of casing and surface equipment and continuous monitoring of surface pressure, pumping rates, volumes of fluids and chemical concentrations during hydraulic fracturing operations. When any pressure differential outside the normal range of operations occurs, pumping is shut down until the cause of the pressure differential is identified and any required remedial measures are completed. Hydraulic fracturing fluid is delivered to our sites in accordance with the U.S. Department of Transportation (DOT) regulations in DOT approved shipping containers using DOT transporters.

We also have procedures to address water use and disposal. This includes evaluating surface and groundwater sources, commercial sources, and potential recycling and reuse of treated water sources. When commercially and technically feasible, we use recycled or treated water. This practice helps mitigate against potential adverse impacts to other water supply sources. When using raw surface or groundwater, we obtain all required water rights or compensate owners for water consumption. We are evaluating additional treatment capability to augment future water supplies at several of our sites. During our drilling and completions operations, we manage waste water to minimize environmental risks and costs. Flowback water returned to the surface is typically contained in steel tanks or pits. Water that is not treated for reuse is typically piped or trucked to waste disposal injection wells, a number of which we operate. These wells are permitted through the Underground Injection Control (UIC) program of the Safe Drinking Water Act (SDWA). We also use commercial UIC permitted water injection facilities for flowback and produced water disposal.

We have not received regulatory citations or notice of suits related to our hydraulic fracturing operations for environmental concerns. We have not experienced a surface release of fluids associated with hydraulic fracturing that resulted in material financial exposure or significant environmental impact. Consistent with local, state and federal requirements, releases are reported to appropriate regulatory agencies and site restoration completed. No remediation reserve has been identified or anticipated as a result of hydraulic fracturing releases experienced to date.

Spill Prevention/Response Procedures. There are various state and federal regulations that are designed to prevent and respond to any spills or leaks resulting from exploration and production activities. In this regard, we maintain spill prevention control and countermeasures programs, which frequently include the installation and maintenance of spill containment devices designed to contain spill materials on location. In addition, we maintain emergency response plans to minimize potential environmental impacts in the event of a spill or leak or any significant hydraulic fracturing well control issue.

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Environmental

A description of our environmental remediation activities is included in Part II, Item 8, "Financial Statements and Supplementary Data", Note 9.

Employees

As of February 28, 2019, we had 372 full-time employees in the United States.

Executive Officers of the Registrant

Our executive officers as of February 28, 2019, are listed below.

Name	Office	Age
Russell E. Parker	President, Chief Executive Officer and Director	42
Raymond J. Ambrose	Senior Vice President, Engineering and Subsurface	46
Chad D. England	Senior Vice President, Operations	39
Kyle A. McCuen	Senior Vice President, Chief Financial Officer and Treasurer	44
Jace D. Locke	Vice President, General Counsel and Corporate Secretary	42

Russell E. Parker

Mr. Parker has been our President and Chief Executive Officer and has served as a member of the Board since November 6, 2017. He was previously Chief Executive Officer of Phoenix Natural Resources LLC (Phoenix), from March 2016 to October 2017. Mr. Parker was the President of Chief Oil & Gas LLC from March 2015 to December 2015, and prior to becoming President, was Vice President of Engineering and Operations from October 2014 to March 2015 and Vice President of Engineering from November 2012 to October 2014. From January 2001 to October 2012, Mr. Parker worked in various engineering and asset management capacities for Hilcorp Energy Company (Hilcorp). Mr. Parker received his BS in Petroleum and Geosystems from the University of Texas at Austin, where he also was recognized as an Outstanding Young Graduate of the Cockrell School of Engineering as well as Distinguished Alumnus of the Petroleum Engineering Department.

Raymond J. Ambrose

Dr. Ambrose has been our Senior Vice President, Engineering and Subsurface since November 6, 2017. He was previously Senior Vice President, Engineering and Business Development for Phoenix from April 2016 to October 2017. Dr. Ambrose worked as Senior Director, Petroleum Engineering for NRG Energy, Inc., from April 2015 until joining Phoenix and as the Chief Reservoir Engineer for Hilcorp from March 2012 to March 2015. Dr. Ambrose earned a BS in chemical engineering with a petroleum minor and an MS in petroleum engineering from the University of Southern California and a PhD from the University of Oklahoma where his dissertation was focused on unconventional gas storage phenomena and rate transient analysis of unconventional reservoirs.

Chad D. England

Mr. England has been our Senior Vice President, Operations, since November 6, 2017. He was previously Senior Vice President of Operations for Phoenix from April 2016 to November 2017. Mr. England worked for Hilcorp as an Operations Manager from September 2010 to April 2016 on the Eagle Ford, Utica and South Texas asset teams. Prior to Hilcorp, he held engineering positions for ConocoPhillips from October 2006 to September 2010. Mr. England received his BS in Mechanical Engineering from Texas A&M University.

Kyle A. McCuen

Mr. McCuen has been our Senior Vice President, Chief Financial Officer and Treasurer since January 1, 2018. He was our interim Chief Financial Officer from February 2017 to December 2017, and our Vice President and Treasurer since August 2013. He was Vice President and Treasurer of EP Energy LLC from May 2012 to August 2013. He previously served in various finance and strategic planning roles at El Paso Corporation, most recently serving as Vice President of Corporate and E&P Planning at El Paso Corporation from October 2011 to May 2012. Mr. McCuen graduated from the University of Texas with a BBA and received an MBA from the University of Houston.

Jace D. Locke

Mr. Locke has been our Vice President, General Counsel and Corporate Secretary since January 1, 2018. He was our Associate General Counsel and Assistant Secretary from August 2013 to December 2017 and was Associate General Counsel and

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Assistant Secretary for EP Energy LLC from May 2012 to August 2013. He previously served as Senior Counsel at El Paso Corporation from November 2007 to May 2012, which included service as Corporate Secretary of El Paso's midstream business unit. Prior to joining El Paso Corporation, Mr. Locke served as an associate at the international law firm of Dewey & LeBoeuf LLP from June 2002 to October 2007. Mr. Locke graduated from the University of Utah with a BS in Political Science and received a JD from Brigham Young University.

Available Information

Our website is http://www.epenergy.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, including related exhibits and supplemental schedules, as soon as is reasonably possible after these reports are filed or furnished with the Securities and Exchange Commission (SEC). The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. All of our SEC filings are also available on the SEC's website at www.sec.gov. Information about each of our Board members, each of our Board's standing committee charters, and our Corporate Governance Guidelines as well as a copy of our Code of Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business and Industry

The prices for oil, natural gas and NGLs are highly volatile and sustained lower prices have adversely affected, and may continue to adversely affect, our business, results of operations, cash flows and financial condition.

Our success depends upon the prices we receive for our oil, natural gas and NGLs. These commodity prices historically have been highly volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. Commodity prices could also remain depressed for a sustained period. The prices for oil, natural gas and NGLs are subject to a variety of factors that are outside of our control, which include, among others:

- regional, domestic and international supply of, and demand for, oil, natural gas and NGLs;
- oil, natural gas and NGLs inventory levels in the United States;
- political and economic conditions domestically and in other oil and natural gas producing countries, including the current conflicts in the Middle East and conditions in Africa, Russia and South America;
- actions of OPEC and state-controlled oil companies relating to oil, natural gas and NGLs price and production controls;
- wars, terrorist activities and other acts of aggression;
- weather conditions and weather patterns;
- technological advances affecting energy consumption and energy supply;
- adoption of various energy efficiency and conservation measures and alternative fuel requirements;
- the price and availability of supplies of, and consumer demand for, alternative energy sources;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGLs;
- volatile trading patterns in capital and commodity-futures markets;
- the strengthening and weakening of the U.S. dollar relative to other currencies;
- changes in domestic governmental regulations, administrative and/or agency actions, and taxes, including potential restrictive regulations associated with hydraulic fracturing operations;
- changes in the costs of exploring for, developing, producing, transporting, processing and marketing oil, natural gas and NGLs;
- availability, proximity and cost of commodity processing, gathering and transportation and refining capacity;
- perceptions of customers on the availability and price volatility of our products, particularly customers' perception of the volatility of oil and natural gas prices over the longer term; and
- variations between product prices at sales points and applicable index prices.

Governmental actions may also affect oil, natural gas and NGLs prices.

The negative impact of low commodity prices on our cash flows could limit our cash available for capital expenditures and ultimately reduce our (i) drilling opportunities, (ii) future production volumes and operating revenues, and (iii) oil and gas reserves. Any resulting decreases in production could result in an additional shortfall in our expected cash flows and require us to further reduce our capital spending or borrow funds to cover any such shortfall. In addition to reducing our cash flows, a prolonged and substantial decline in commodity prices could negatively impact our proved oil and natural gas reserves, which in turn, may result in a significant write-down of the carrying value of our proved properties through a corresponding impairment charge on our income statement. For example, given the decline in commodity prices since the third quarter of 2018 and significant reduction in future development capital allocated to the Permian basin, we incurred non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin in the fourth quarter of 2018. In addition to the impairment charges recorded as of December 31, 2018, future commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in a further impairment of the carrying value of our proved and/or unproved properties in the future with our Permian and/or other areas.

Commodity prices also affect our ability to access funds under our reserve-based revolving credit facility (the RBL Facility) and through the capital markets and may adversely affect our ability to refinance our debt. The amount available for borrowing under the RBL Facility is subject to a borrowing base, which was $1.36 billion with commitments of $629 million as of February 28, 2019. Our borrowing base is determined by our lenders taking into account our proved reserves, and is subject to periodic redeterminations (in April and November) based on pricing models determined by the lenders at such time. Declines in oil, natural gas and NGLs prices have and could continue to adversely impact the value of our proved reserves and, in turn, the bank pricing used by our lenders to determine our borrowing base. Upon redetermination, we would be required to repay amounts outstanding under our credit facility should they exceed the redetermined borrowing base. In addition, the availability of borrowings under the RBL Facility is subject to various financial and non-financial covenants and restrictions, which could be directly and negatively affected by falling commodity prices or a worsening of our financial condition. Any of these factors could further negatively impact our liquidity, our ability to replace our production and our future rate of growth. On the other hand, increases in commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in commodity prices. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

We have significant capital programs in our business that may require us to access capital markets, and any inability to obtain access to the capital markets in the future at competitive rates, or any negative developments in the capital markets, could have a material adverse effect on our business.

We have significant capital programs in our business, which may require us to access the capital markets in order to continue the development of our properties. Since we are rated below investment grade and are highly levered, our ability to access the capital markets or the cost of capital could be negatively impacted, which could require us to forego opportunities or could make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us or have greater financial resources. There is a risk that our non-investment grade credit rating may be further lowered in the future in light of the sustained lower commodity price environment as well as our substantial leverage, limited liquidity, undesirable credit profile and other factors. Reductions in our credit rating could have a negative impact on us. For example, a lower credit rating could limit our available liquidity if we are required to post incremental collateral on transportation contract obligations or other contractual commitments.

In addition, the turmoil in recent years in the credit markets for companies in the energy sector with volatile commodity prices has led to reduced credit availability, tighter lending standards and higher interest rates on loans for energy companies, especially non-investment grade companies. While we cannot predict the future condition of the credit markets, future turmoil in the credit markets could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be impaired. Our primary source of liquidity beyond cash flow from operations is our RBL Facility. At February 28, 2019, we had $190 million outstanding under the facility, a borrowing base of $1.36 billion and commitments of $629 million.

Although we believe that the banks participating in the RBL Facility have adequate capital and resources, we can provide no assurance that all of those banks will continue to operate as going concerns in the future, or continue to participate in the facility. If any of the banks in our lending group were to fail, or choose not to participate, it is possible that the borrowing capacity under the RBL Facility would be reduced. In the event of such reduction, we could be required to obtain capital from alternate sources or find additional RBL participants in order to finance our capital needs. Our options for addressing such capital constraints would include, but not be limited to, obtaining commitments from the remaining banks in the lending group and accessing the public and private capital markets. In addition, we may delay certain capital expenditures to ensure that we maintain appropriate levels of liquidity. If it became necessary to access additional capital, any such alternatives could have terms less favorable than the current terms under the RBL Facility, which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our substantial indebtedness could adversely affect our ability to operate our business, we may not be able to generate sufficient cash flows to service our indebtedness and we may be forced to take actions to satisfy our debt obligations that may not be successful.

We are a highly leveraged company with significant debt and debt service obligations. As of December 31, 2018, our total debt was approximately $4.4 billion, comprised of $8 million in senior secured term loans maturing in 2019, $738 million in senior unsecured notes due in 2020, 2022 and 2023, and $3.6 billion in senior secured notes due in 2024, 2025 and 2026. For

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the year ended December 31, 2018, we incurred $365 million in interest expense. Our substantial indebtedness could have material consequences for our business, results of operations and financial condition, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to debt service payments thereby reducing the availability of cash for working capital, capital expenditures, acquisitions or general corporate purposes;
- limiting our ability to borrow money for our working capital, capital expenditures (including the development of reserves), debt service requirements, strategic initiatives or other purposes;
- exposing us to more liquidity risks, including breach of covenants and default risks, especially during times of financial and commodity price volatility;
- making us more vulnerable to downturns in our business or the economy;
- limiting our flexibility in planning for, or reacting to, changes in our operations or business;
- increasing our leverage relative to our competitors, which may place us at a competitive disadvantage;
- restricting us from making strategic acquisitions, engaging in development activities, introducing new technologies or exploiting business opportunities;
- causing us to make non-strategic divestitures;
- requiring us to secure additional sources of liquidity, which may or may not be available to us; or
- causing us to issue equity thereby diluting existing stockholders.

Our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Lower commodity prices have negatively impacted our revenues, earnings and cash flows, and sustained low oil and natural gas prices will likely have an adverse effect on our liquidity and financial condition.

As of February 28, 2019, we had only $420 million of availability under the RBL Facility and could issue only an additional $371 million in senior secured debt. In addition, in May 2020, $182 million of our senior unsecured notes will mature. There can be no assurance that we will have the ability to borrow or otherwise raise the amounts necessary to refinance our indebtedness as it matures. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time, and any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business and operations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our ability to make payments on our indebtedness and our business, financial condition and results of operations.

In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a default under that indebtedness, which would likely cause cross defaults under our other indebtedness, which could force us into bankruptcy or liquidation. Please see “Our debt agreements contain restrictions that limit our flexibility in operating our business.” 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 our debt service and other obligations. Our debt instruments restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

We may be unable to successfully effectuate any or all of the strategic alternatives that we must implement in order to service our substantial indebtedness.

In May 2020, $182 million of our senior unsecured notes will mature. We project that as of May 2020 we will not have sufficient liquidity available to repay these notes and meet our working capital needs and/or fund our planned capital

expenditures or meet other near-term maturities. In order to address this projected shortfall in liquidity, we are evaluating
certain other sources of incremental liquidity, including issuing additional debt, refinancing our debt and selling assets.
However, we may fail to effectuate any such strategic alternatives on commercially reasonable terms or at all. If we fail to
obtain the necessary additional liquidity, there may be substantial doubt that we would be able to continue as a going concern

beginning in May 2020. Even if we are able to implement such strategic alternatives, they may be insufficient to meet our debt
and other obligations. Furthermore, such strategic alternatives may adversely affect our creditors or our existing stockholders,
potentially resulting in the loss of all or substantially all of their investment in us.

Under the RBL Facility, we are required to deliver audited consolidated financial statements without a going concern or like qualification or explanation. The inclusion of a going concern explanation in our audited financial statements would, in the absence of a waiver or other suitable relief, result in an event of default under the RBL Facility, after which the lenders thereunder could accelerate the outstanding indebtedness. In addition, an event of default under our RBL Facility could trigger cross-defaults under our other debt agreements, including our senior secured term loan and our senior secured and unsecured notes, which could also result in the acceleration of those obligations by the lenders thereunder.

Our ability to issue additional debt and/or refinance our debt depends on numerous factors, such as our financial condition and the terms of our existing debt agreements, which include restrictions on our ability to, among other things, incur
additional debt and prepay, redeem or repurchase certain debt. Our ability to issue additional debt and/or refinance our debt is
also subject to many factors that are beyond our control, such as the condition of the capital markets in general. Even if we are
able to issue additional debt and/or refinance our debt, we could, as a result, become subject to higher interest rates and/or more
onerous debt covenants, which could further restrict our ability to operate our business. To the extent that we seek to sell assets in order to meet our debt and other obligations, we may fail to effectuate any such dispositions for fair market value, in a timely manner or at all. Furthermore, the proceeds that we realize from any such dispositions may be inadequate to meet our debt and other obligations.

We have been notified by the NYSE that we are currently out of compliance with the NYSE’s minimum share price requirement, and are at risk of the NYSE delisting our common stock, which would have an adverse impact on the trading volume, liquidity and market price of our common stock.

Our common stock is currently listed on the NYSE, and the continued listing of our common stock on the NYSE is subject to our compliance with a number of listing standards. On January 3, 2019, we were notified by the NYSE that we were not in compliance with NYSE continued listing standards because the average closing price of our shares of common stock had fallen below $1.00 per share over a period of 30 consecutive trading days.

Under the NYSE’s rules, we have six months following receipt of the notification to regain compliance with the minimum share price requirement. We can regain compliance at any time during the six-month cure period if on the last trading day of any calendar month our common stock has a closing share price of at least $1.00 and an average closing share price of at least $1.00 over the 30 trading-day period ending on the last trading day of such month. During this six-month period, our common stock will continue to be listed and traded on the NYSE, subject to compliance with other continued listing requirements.

If we do not regain compliance with the minimum share price requirement by the end of the cure period, the common stock will be subject to the NYSE’s suspension and delisting procedures. The commencement of suspension or delisting procedures by the NYSE remains, at all times, at the discretion of the NYSE and would be publicly announced by the NYSE. A delisting of our common stock from the NYSE could negatively impact us, as it would likely reduce the liquidity and market price of our common stock and reduce the number of investors willing to hold or acquire our common stock. In addition, our ability to access equity markets to obtain financing, and attract and retain personnel by means of equity compensation, would be impaired. Furthermore, if our common stock were suspended or delisted, we would expect decreases in analyst coverage, market making activity and information available concerning trading prices and volume, and fewer broker-dealers would be willing to execute trades with respect to our common stock.

Our failure to comply with the covenants under our debt agreements may result in the occurrence of an event of default under such agreements. If an event of default occurs, we may become subject to cross-defaults under certain of our remaining debt agreements, making us unable to meet our debt obligations that become immediately due.

An event of default may occur under our debt agreements due to our failure to comply with the covenants thereunder. If an event of default occurs and/or our lenders accelerate our obligations under such agreements, cross-defaults will exist under certain of our remaining indebtedness and we may not be able to repay our debt obligations that become immediately due. For example, the RBL Facility requires us to comply with certain financial covenants and our failure to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If we become subject to cross defaults under our other indebtedness due to the occurrence of an event of default under the RBL Facility, the lenders or holders under the RBL Facility and our other secured indebtedness could proceed against the collateral granted to them to secure that indebtedness, which represents the substantial portion of our assets.

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The success of our business depends upon our ability to find and replace reserves that we produce.

Similar to our competitors, we have a reserve base that is depleted as it is produced. Unless we successfully replace the reserves that we produce, our reserves will decline, which will eventually result in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We historically have replaced reserves through both drilling and acquisitions. The business of exploring for, developing or acquiring reserves requires substantial capital expenditures. If we do not continue to make significant capital expenditures (for any reason, including our access to capital resources becoming limited) or if our exploration, development and acquisition activities are unsuccessful, we may not be able to replace the reserves that we produce, which would negatively impact us. As a result, our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs or at all. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, results of operations and financial condition would be materially adversely affected. We have reduced our PUD reserves by 64 MMBoe, or approximately 41% as of December 31, 2018 based on the adjustment to our PUD bookings methodology from a five-year to a three-year timeframe. We took this action because we do not currently have the financial resources to develop our PUD reserves in years four or five. See Part I, Item 1. "Business" under the heading Oil and Natural Gas Properties for further discussion on our proved reserves.

Our oil and natural gas drilling and producing operations involve many risks, and our production forecasts may differ from actual results.

Our success will depend on our drilling results which are subject to the risk that (i) we may not encounter commercially productive reservoirs or (ii) if we encounter commercially productive reservoirs, we either may not fully recover our investments or our rates of return will be less than expected. Our past performance should not be considered indicative of future drilling performance. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different from actual results and such differences could be material. As of December 31, 2018, our proved reserves reflect the effects of adjusting our PUD bookings methodology from a five-year to a three-year timeframe. We took this action because we do not currently have the financial resources to develop our PUD reserves in years four or five. See Part I, Item 1. "Business" under the heading Oil and Natural Gas Properties for further discussion on our proved reserves.

Our decisions to purchase, explore, develop or otherwise exploit 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. In addition, the results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may increase the cost of, or curtail, delay or cancel drilling operations, including the following:

- unexpected drilling conditions;
- delays imposed by or resulting from compliance with regulatory and contractual requirements, including requirements on sourcing of materials;
- unexpected pressure or irregularities in geological formations;
- equipment failures or accidents;

- fracture stimulation accidents or failures;
- adverse weather conditions;
- declines in oil and natural gas prices;
- surface access restrictions with respect to drilling or laying pipelines;
- shortages (or increases in costs) of water used in hydraulic fracturing, especially in arid regions or regions that have been experiencing severe drought conditions;

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- shortages or delays in the availability of, increases in the cost of, or increased competition for, drilling rigs and crews, fracture stimulation crews, equipment, pipe, chemicals and supplies and transportation, gathering, processing, treating or other midstream services; and
- limitations or reductions in the market for oil and natural gas.

Additionally, the occurrence of certain of these events, particularly equipment failures or accidents, could impact third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries or death or significant property damage. As a result, we face the possibility of liabilities from these events that could materially adversely affect our business, results of operations and financial condition.

In addition, uncertainties associated with enhanced recovery methods may not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate and we may be unable to realize an acceptable return on our investments in certain of our projects. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict.

Our drilling locations are scheduled to be drilled over a number of years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has identified and scheduled potential drilling locations as an estimate of our future multi-year drilling activities on our existing acreage. All of our potential drilling locations, particularly our potential drilling locations for oil, represent a significant part of our strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGLs prices, costs and drilling results. If our capital resources are insufficient to support our drilling activities or other risks materialize, we may be unable to drill and develop these locations. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells where a final investment decision has been made to drill within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. We have adjusted our PUD bookings methodology from a five-year to a three-year timeframe because we do not currently have the financial resources to develop our PUD reserves in years four or five.

Certain of our undeveloped leasehold acreage is subject to leases that will expire in several years unless production is established on units containing the acreage.

Although many of our reserves are located on leases that are held-by-production or held by continuous development, we do have provisions in a number of our leases that provide for the lease to expire unless certain conditions are met, such as drilling having commenced on the lease or production in paying quantities having been obtained within a defined time period. If commodity prices remain lower or we are unable to allocate sufficient capital to meet these obligations, there is a risk that some of our existing proved reserves and some of our unproved inventory/acreage could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in impairment of remaining costs and a reduction in our reserves and our growth opportunities (or the incurrence of significant costs) and therefore could have a material adverse effect on our financial results.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

Our future drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

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We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and increase our proved reserves and production. In 2018, we spent total capital of $644 million (not including approximately $340 million in acquisition capital and adjustments under a joint venture agreement). We have established a capital budget for the first quarter of 2019 of approximately $160 million to $170 million (not including acquisition capital) and we intend to rely on cash flow from operating activities and available cash and borrowings under the RBL Facility as our primary sources of liquidity. As of December 31, 2018, our available liquidity was approximately $537 million, including available cash and borrowings under the RBL Facility. For a discussion of liquidity, see Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources”. We also may engage in asset sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete monetization transactions on terms we find acceptable. There can be no assurance that such sources will be available to us or sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows continue to decrease in the future as a result of declines in commodity prices or a reduction in production levels, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to increase or even maintain our reserves and production levels.

Interest rates could negatively affect our financing costs and ability to access capital. We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to potentially rising interest rates in the future to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund our operations. Disruptions in capital and credit markets in the past have resulted in higher interest rates on new publicly issued debt and increased costs for variable interest rate debt.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable or at all. Additionally, any acquisition involves potential risks, including (i) the inability to integrate acquired businesses successfully and produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate, (ii) the assumption of liabilities that were not disclosed to us and for which contractual protections prove inadequate or that exceed our estimates; and (iii) the potential loss of key customers and/or employees. Any of the above risks could significantly impair our ability to manage our business, complete or effectively integrate acquisitions and may have a material adverse effect on our business, results of operations and financial condition.

Retained liabilities associated with businesses or assets that we have sold could exceed our estimates and we could experience difficulties in managing these liabilities.

We have sold various assets and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold, including breaches of warranties, environmental expenditures, asset retirements and other representations that we have provided. We may also be subject to retained liabilities with respect to certain divested assets by operation of law. For example, the recent and sustained decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging or abandonment obligations that attach to such assets. In that event, due to operation of law, we may be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. Although we believe that we have established appropriate reserves for any such liabilities, we could be required to accrue additional amounts in the future and these amounts could be material.

Our use of derivative financial instruments could result in financial losses or could reduce our income.

We use fixed price financial options and swaps to mitigate our commodity price and basis exposures. However, we do not typically hedge all of these exposures, and typically do not hedge any of these exposures beyond several years. Our derivative contracts (primarily fixed price derivatives) as of December 31, 2018, will allow us to realize a weighted average price of $55.93 and $60.75 per barrel on 14 MMBbls and 2 MMBbls of oil in 2019 and 2020, respectively, and $2.86 per MMBtu on 26 TBtu of natural gas in 2019. Subsequent to December 31, 2018, we entered into additional derivative contracts on 0.3 MBbls of 2019 Midland vs. Cushing oil basis swaps with an average price of $(1.50) per barrel of oil and 9.9 MMBbls of 2020 WTI oil three-way collars with a ceiling price of $65.13, a floor price of $55.00 and a sub-floor price of $45.00 per barrel of oil. We have no price protection currently past this timeframe. As a result, we have substantial commodity price and basis exposure since our business has multi-year drilling programs for our proved reserves and unproved resources, particularly as our existing hedges roll off.

The derivative contracts we enter into to mitigate commodity price risk are not designated as accounting hedges and are therefore marked to market. As a result, we experience volatility in our revenues and net income as a result of changes in commodity prices, counterparty non-performance risks, correlation factors and changes in the liquidity of the market. Furthermore, the valuation of these financial instruments involves estimates based on assumptions that could prove to be incorrect and result in financial losses. Although we have internal controls in place that impose restrictions on the use of derivative instruments, there is a risk that such controls will not be complied with or will not be effective, and we could incur substantial losses on our derivative transactions. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital and liquidity when commodity prices or change.

To the extent we enter into derivative contracts to manage our commodity price and basis exposures, we may forego the benefits we could otherwise experience if such prices were to change favorably and we could experience losses to the extent that these prices were to increase above the fixed price. In addition, these hedging arrangements also expose us to the risk of financial loss in the following circumstances, among others:

- when production is less than expected or less than we have hedged;
- when the counterparty to the hedging instrument defaults on its contractual obligations;
- when there is an increase in the differential between the underlying price in the hedging instrument and actual prices received; and
- when there are issues with respect to legal enforceability of such instruments.

Our derivative counterparties are typically large financial institutions. We are subject to the risk of loss on our derivative instruments as a result of non-performance by our counterparties, especially when there is a significant decline in commodity prices. The ability of our counterparties to meet their obligations to us on hedge transactions could reduce our revenue from hedges at a time when we are also receiving a lower price for our oil and natural gas sales. As a result, our business, results of operations and financial condition could be materially adversely affected.

In 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) provided for federal oversight of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act mandated that the Commodity Futures Trading Commission (the CFTC), the SEC and certain federal regulators of financial institutions (the Prudential Regulators) adopt rules or regulations to implement the Dodd-Frank Act and provide definitions of terms. Among other things, the Dodd-Frank Act and associated rules established margin requirements and required clearing and trade execution practices for certain market participants and resulted in certain market participants curtailing and/or ceasing their derivatives activities. The Dodd-Frank Act and associated rules also place limitations on our ability to enforce remedies against our swap counterparties who are regulated by the Prudential Regulators, and proposed rules would impose position limits on some market participants and also modify the capital reserve requirements applicable to our swap counterparties. While we qualify for various exceptions under the Dodd-Frank Act and associated rules as well as similar foreign regulations enacted by the European Union and other non-U.S. jurisdictions, most if not all of our hedge counterparties are subject to various provisions of these regulations and proposed regulations, which could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and related rules and/or similar foreign regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Estimating our reserves involves uncertainty, our actual reserves will likely vary from our estimates, and negative revisions to our reserve estimates in the future could result in decreased earnings and/or losses and impairments.

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All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information is evaluated and prepared by an independent petroleum engineering consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in our estimates varying considerably from actual results. Estimating quantities of proved reserves is complex and involves significant interpretation and assumptions with respect to available geological, geophysical and engineering data, including data from nearby producing areas. It also requires us to estimate future economic factors, such as commodity prices, production costs, plugging and abandonment costs, severance, ad valorem and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Furthermore, estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices (including commodity prices and the cost of oilfield services), economic conditions and government restrictions and regulations. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Therefore, our reserve information represents an estimate and is often different from the quantities of oil and natural gas that are ultimately recovered or proven recoverable.

The SEC rules require the use of a 10% discount factor for estimating the value of our future net cash flows from reserves and the use of a historical 12-month average price. This discount factor may not necessarily represent the most appropriate discount factor, given our costs of capital, actual interest rates and risks faced by our exploration and production business, and the average historical price will not generally represent the future market prices for oil and natural gas over time. Any significant change in commodity prices could cause the estimated quantities and net present value of our reserves to differ and these differences could be material. You should not assume that the present values referred to in this Annual Report on Form 10-K represent the current market value of our estimated oil and natural gas reserves. Finally, the timing of the production and the expenses related to the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value.

We account for our activities under the successful efforts method of accounting. Changes in the estimated fair value of these reserves could result in a write-down in the carrying value of our oil and natural gas properties, which could be substantial and could have a material adverse effect on our net income and stockholders' equity. Lower estimated fair value of these reserves could also result in lower recorded reserves, which would increase our depreciation, depletion and amortization rates and decrease earnings.

A portion of our proved reserves are undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. We have adjusted our PUD bookings methodology from a five-year to a three-year timeframe because we do not currently have the financial resources to develop our PUD reserves in years four or five.

In addition, because our proved reserve base consists primarily of unconventional resources, the costs of finding, developing and producing those reserves may require capital expenditures that are greater than more conventional resource plays. Our estimates of proved reserves assume that we can and will make these expenditures and conduct these operations successfully. However, future events, including commodity price changes and our ability to access capital markets, may cause these assumptions to change.

Our business is subject to competition from third parties, which could negatively impact our ability to succeed.

The oil, natural gas and NGLs businesses are highly competitive. We compete with third parties in the search for and acquisition of leases, properties and reserves, as well as the equipment, materials and services required to explore for and produce our reserves. There has been intense competition for the acquisition of leasehold positions, particularly in many of the oil and natural gas shale plays. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to fund and consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil properties. Similarly, we compete with many third parties in the sale of oil, natural gas and NGLs to customers, some of which have substantially larger market positions, marketing staff and financial resources than us. Our competitors include major and independent oil and natural gas companies, as well as financial services companies and investors, many of which have financial and other resources that are substantially greater than those available to us. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition,

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these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices.

Furthermore, there is significant competition between the oil and natural gas industry and other industries producing energy and fuel, which may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which could negatively impact our competitive position.

Our industry is cyclical, and at certain times historically there have been shortages of drilling rigs, equipment, supplies or qualified personnel. A sustained decline in commodity prices can also reduce the number of service providers for such drilling rigs, equipment, supplies or qualified personnel, contributing to or also resulting in the shortages. Alternatively, during periods of high prices, the cost of rigs, equipment, supplies and personnel can fluctuate widely, significant cost inflation may occur, and availability may be limited. These services may not be available on commercially reasonable terms or at all. We cannot predict the extent to which these conditions will exist in the future or their timing or duration. The high cost or unavailability of drilling rigs, equipment, supplies, personnel and other oil field services could significantly decrease our profit margins, cash flows and operating results and could restrict our ability to drill the wells and conduct the operations that we currently have planned and budgeted or that we may plan in the future. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Our business is subject to operational hazards and uninsured risks that could have a material adverse effect on our business, results of operations and financial condition.

Our oil and natural gas exploration and production activities are subject to all of the inherent risks associated with drilling for and producing natural gas and oil, including the possibility of:

- Adverse weather conditions, natural disasters, and/or other climate related matters—including extreme cold or heat, lightning and flooding, severe drought, fires, earthquakes, hurricanes, tropical storms, tornadoes and other natural disasters. Although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns could also have a negative impact upon our operations in the future, particularly with regard to any of our facilities that are located in or near coastal regions;
- Acts of aggression on critical energy infrastructure—including terrorist activity or “cyber security” events. We are subject to the ongoing risk that one of these incidents may occur which could significantly impact our business operations and/or financial results. Should one of these events occur in the future, it could impact our ability to operate our drilling and exploration processes, our operations could be disrupted, and/or property could be damaged resulting in substantial loss of revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation and litigation and/or inaccurate information reported from our exploration and production operations to our financial applications, to our customers and to regulatory entities; and
- Other hazards—including the collision of third-party equipment with our infrastructure; explosions, equipment malfunctions, mechanical and process safety failures, well blowouts, formations with abnormal pressures and collapses of wellbore casing or other tubulars; events causing our facilities to operate below expected levels of capacity or efficiency; uncontrollable flows of natural gas, oil, brine or well fluids, release of pollution or contaminants (including hydrocarbons) into the environment (including discharges of toxic gases or substances) and other environmental hazards.

Each of these risks could result in (i) damage to and destruction of our facilities; (ii) damage to and destruction of property, natural resources and equipment; (iii) injury or loss of life; (iv) business interruptions while damaged energy infrastructure is repaired or replaced; (v) pollution and other environmental damage; (vi) regulatory investigations and penalties; and (vii) repair and remediation costs. Any of these results could cause us to suffer substantial losses.

While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels and limits on our maximum recovery and do not cover all risks. For example, from time to time, we may not carry, or may be unable to obtain, on terms that we find acceptable and/or reasonable, insurance coverage for certain exposures, including, but not limited to certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm/hurricane exposures and, in limited

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circumstances, certain political risk exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their insurance coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance, will not compensate us fully for our losses. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Some of our operations are subject to joint ventures or operations by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A small portion of our operations and interests are operated by third-party working interest owners. In such cases, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties, (iii) we are dependent on third parties to fund their required share of capital expenditures and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets.

The insolvency, failure to perform and/or breach its obligations by an operator of our properties could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. As a result, the success and timing of our drilling and development activities on properties operated by others and the economic results derived therefrom depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs, to require us to pay our proportionate share of the defaulting party's share of costs.

We currently sell most of our oil production to a limited number of significant purchasers. The loss of one or more of these purchasers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition or results of operations.

For the year ended December 31, 2018, nine purchasers accounted for approximately 90% of our oil revenues. We depend upon a limited number of significant purchasers for the sale of most of our production. The loss of any of these customers, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production.

We are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.

Our operations, and the energy industry in general, are subject to a complex set of federal, state and local laws and regulations over the following activities, among others:

- the location of wells;
- methods of drilling and completing wells;
- allowable production from wells;
- unitization or pooling of oil and gas properties;
- spill prevention plans;
- limitations on venting or flaring of natural gas;
- disposal of fluids used and wastes generated in connection with operations;
- access to, and surface use and restoration of, well properties;
- plugging and abandoning of wells, even if we no longer own and/or operate such wells;
- air quality and emissions, noise levels and related permits;

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- gathering, transportation and marketing of oil and natural gas (including NGLs);
- taxation;
- protection of threatened or endangered species;
- operations conducted on lands lying within wilderness, wetlands, and ecologicially or seismically sensitive areas;
- competitive bidding rules on federal and state lands; and
- the sourcing and supply of materials needed to operate.

Generally, the regulations have become more stringent and have imposed more limitations on our operations and, as a result, have caused us to incur more costs to comply. Many required approvals are subject to considerable discretion by the regulatory agencies with respect to the timing and scope of approvals and permits issued. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned or at all. Delays in obtaining regulatory approvals or permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with excessive conditions or costs could have a material negative impact on our operations and financial results. We may also incur substantial costs in order to maintain compliance with these existing laws and regulations, including costs to comply with new and more extensive reporting and disclosure requirements. Failure to comply with such requirements may result in the suspension or termination of operations, may subject us to criminal as well as civil and administrative penalties, and may expose us to fines and penalties. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Also, some of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we have drilling and production operations that are located on federal lands, which are regulated by the DOI, particularly by the Bureau of Land Management (BLM). We also have operations on Native American tribal lands, which are regulated by the DOI, particularly by the Bureau of Indian Affairs (BIA), as well as local tribal authorities. Operations on these properties are often subject to additional regulations and compliance obligations, which can delay our access to such lands and impose additional compliance costs. There are also various laws and regulations that regulate various market practices in the industry, including antitrust laws and laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission and the CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years.

We are exposed to the credit risk of our counterparties, contractors and suppliers.

We have significant credit exposure related to our sales of physical commodities, payments to contractors and suppliers, hedging activities and to the non-operating working interest owners who are counterparties to our operating agreements. If our counterparties become insolvent or otherwise fail to make payments/or perform within the time required under our contracts, our results of operations and financial condition could be materially adversely affected. Although we maintain strict credit policies and procedures and credit insurance in some cases, they may not be adequate to fully eliminate the credit risk associated with our counterparties, contractors and suppliers.

We are exposed to the performance risk of our key contractors and suppliers.

We rely on contractors for certain construction, drilling and completion operations and we rely on suppliers for key materials, supplies and services, including steel mills, pipe and tubular manufacturers and oil field service providers. We also rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. There is a risk that such contractors and suppliers may experience credit and performance issues triggered by a sustained low or a volatile commodity price environment that could adversely impact their ability to perform their contractual obligations with us, including their performance and warranty obligations. This could result in delays or defaults in performing such contractual obligations and increased costs to seek replacement contractors, each of which could negatively impact us. We could also be exposed to liability that we would otherwise be indemnified for by these counterparties should they become insolvent or are otherwise unable to satisfy their obligations under their indemnities.

The Sponsors and other legacy investors own more than 75 percent of the equity interests in us and may have conflicts of interest with us and/or public investors.

Investment funds affiliated with, and one or more co-investment vehicles controlled by, our Sponsors (affiliates of Apollo Global Management LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively, the Sponsors) and other legacy investors collectively own more than 75 percent of our equity interests and such persons or their designees hold substantially all of the seats on our board of directors. As a result, the Sponsors and such other investors have control over our decisions to enter into certain corporate transactions and have the ability to prevent any transaction that typically would require the approval of stockholders, regardless of whether holders of our notes or stock believe that any such transactions are in their own best interests. For example, the Sponsors and other legacy investors could collectively cause us to make acquisitions that increase the amount of our indebtedness or to sell assets, or could cause us to issue additional equity, debt, or declare dividends or other distributions to our equity holders. Furthermore, one or more of our Sponsors may have certain conflicts of interest with our public stockholders in the event of a restructuring of our business, particularly to the extent any such Sponsor also holds our notes in addition to their equity interests in us. So long as investment funds affiliated with the Sponsors and other such investors continue to indirectly own a majority of the outstanding shares of our equity interests or otherwise control a majority of our board of directors, these investors will continue to be able to strongly influence or effectively control our decisions. The indentures governing the notes and the credit agreements governing the RBL Facility and our senior secured term loan permit us, under certain circumstances, to pay advisory and other fees, pay dividends and make other restricted payments to the Sponsors and other investors, and the Sponsors and such other investors or their respective affiliates may have an interest in our doing so.

Additionally, the Sponsors and other legacy investors are in the business of making investments in companies and may from time to time acquire and hold interests in businesses that compete directly or indirectly with us or that supply us with goods and services. These persons may also pursue acquisition opportunities that may be complementary to (or competitive with) our business, and as a result those acquisition opportunities may not be available to us. In addition, the Sponsors' and other investors' interests in other portfolio companies could impact our ability to pursue acquisition opportunities.

Our strategy involves drilling in shale plays using some of the latest available horizontal drilling and completion techniques, the results of which are subject to drilling and completion technique risks, and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest horizontal drilling and completion techniques in order to maximize cumulative recoveries and therefore optimize our returns. Drilling risks that we face include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently longer period. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and natural gas industry is subject to rapid and significant advancements in technology, resulting in new products and services. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that may allow them now or in the future to enjoy technological advantages before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Our business depends on access to oil, natural gas and NGLs processing, gathering and transportation systems and facilities.

The marketability of our oil, natural gas and NGLs production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity will exist or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these facilities for an extended period of time could negatively impact our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water currently is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. In times of drought, we may be subject to local or state restrictions on the amount of water we procure to help protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our operations. Productive zones frequently contain water that must be removed in order for the oil and natural gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce oil and natural gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our oil and natural gas wells may affect our ability to produce our oil and natural gas wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

If commodity prices decrease and/or development capital is significantly reduced, we may be required to take write-downs of the carrying values of our properties, which could result in a material adverse effect on our results of operations and financial condition.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for impairment. Under the successful efforts method of accounting, we review our oil and natural gas properties upon a triggering event (such as a significant and sustained decline in forward commodity prices or a significant change in current and anticipated allocated capital) to determine if impairment of such properties is necessary. Significant undeveloped leasehold costs are assessed for impairment at a lease level or resource play level based on our current exploration plans, while leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally assessed for impairment by major prospect area. Proved oil and natural gas property values are reviewed when circumstances suggest the need for such a review and may occur if actual discoveries in a field are lower than anticipated reserves, reservoirs produce below original estimates, capital allocated for development is significantly reduced and/or if commodity prices fall to a level that significantly affects anticipated future cash flows on the property. If required, the proved properties are written down to their estimated fair market value based on proved reserves and other market factors. These impairment charges could have a material adverse effect on our results of operations and financial condition for the periods in which such charges are taken.

Given the decline in commodity prices since the third quarter of 2018 and significant reduction in future development capital allocated to the Permian basin, we incurred non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin in the fourth quarter of 2018. In addition to the impairment charges recorded as of December 31, 2018, future commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in a further impairment of the carrying value of our proved and/or unproved properties in the future with our Permian and/or other areas. See Part II, Item 8. "Financial Statements and Supplementary Data", Note 3, for further information.

Our operations are subject to governmental laws and regulations relating to environmental matters, which may expose us to significant costs and liabilities and/or significant delays that could exceed current expectations.

Our business is subject to environmental laws and regulations. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, spill prevention, control and countermeasures, as well as regulations designed for the protection of threatened or endangered species. Accordingly, there is inherent risk of incurring significant environmental liabilities due to these matters as a result of historical industry operations and waste disposal practices by us or third parties not under our control. Additionally, these proposed and/or implemented regulations could materially impact the costs of exploration and production operations and cause substantial delays in the receipt of regulatory approvals from both an environmental and safety perspective. It is possible that more stringent regulations might be enacted or delays in receiving permits may occur in other areas, including drilling operations on other federal or state lands.

In the course of our exploration and production operations, we and/or other owners and operators of these facilities may have generated or disposed of wastes that polluted the soil, surface water or groundwater at our facilities and adjacent properties. As such, we could be subject to claims for personal injury and/or natural resource and property damage (including site clean-up and restoration costs) related to the environmental, health or safety impacts of our oil and natural gas production activities, and we have been from time to time, and currently are, named as a defendant in litigation related to such matters. Under certain laws, we also could be subject to strict liability (i.e., no showing of “fault” is required) that, in some circumstances, may be joint and several for the costs of removing or remediating contamination regardless of whether such contamination was the result of our activities, even if the operations were in compliance with all applicable laws at the time the contamination occurred and even if we no longer own and/or operate on the properties. We may also be subject to litigation from private parties (e.g. property owners, facility owners) who may pursue legal actions to enforce compliance, as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. While to date none of these remediation obligations or claims have involved costs that have materially and adversely affected our business, we cannot predict with certainty whether future costs of newly discovered or new contamination might result in a materially adverse impact on our business or operations.

Legislation and regulatory initiatives intended to address pipeline safety could increase our operating costs.

Some pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation (DOT), and/or various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the “Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016” (the “PIPES Act”), which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions, and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

Recently, the PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand integrity management requirements beyond High Consequence Areas to gas pipelines in newly defined Moderate Consequence Areas. The public comment period closed in July 2016. Also, in January 2017, the PHMSA released an advance copy of its final rules to expand its safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws, and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extend the PHMSA will move forward with its regulatory reforms.

Regulation relating to climate change and energy conservation could result in increased operating costs and reduced demand for oil and natural gas we produce.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases (GHGs). The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of

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the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs.

Additionally, on November 15, 2016, the BLM finalized a waste prevention rule for oil and gas facilities on onshore federal and Indian leases to prohibit venting, limit flaring, require leak detection, and allow adjustment of royalty rates for new leases. The rule went into effect in January 2017 and could have required installation of tank vapor controls at certain existing well sites in the NEU area at a then-estimated cost of approximately $5 million. However, on September 28, 2018, the BLM published final amendments to the waste prevention rule that eliminated certain air quality provisions, including those that would require us to install tank vapor controls. Litigation filed by state and environmental groups to challenge the amended final rule is on-going at this time.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The text of the resulting Paris Agreement calls for nations to undertake “ambitious efforts” to “hold the increase in global average temperatures to well below 2 ºC above preindustrial levels and pursue efforts to limit the temperature increase to 1.5 ºC above pre-industrial levels;” reach global peaking of GHG emissions as soon as possible; and take action to conserve and enhance sinks and reservoirs of GHGs, among other requirements. The Paris Agreement went into effect in November 2016. However, in June 2017, the President announced that the United States would withdraw from the Paris Agreement, and began negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Presidential administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Regulation of GHG emissions could result in reduced demand for our products, as oil and natural gas consumers seek to reduce their own GHG emissions. As our operations also emit GHGs directly, current and future laws or regulations limiting such emissions could increase our own costs. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could have a material adverse effect on our business, results of operations and financial condition.

Further, there have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (i) shift more power generation to renewable energy sources and (ii) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGLs consumption. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital.

Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

In addition, to the extent climate change results in more severe weather and significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic effects, our own, our counterparties’ or our customers’ operations may be disrupted, which could result in a decrease in our available products or reduce our customers’ demand for our products.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Our operations could result in an equipment malfunction or oil spill that could expose us to significant liability.

Despite the existence of various procedures and plans, there is a risk that we could experience well control problems in our operations. As a result, we could be exposed to regulatory fines and penalties, as well as landowner lawsuits resulting from any spills or leaks that might occur. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition to the extent we are not fully covered by our insurance, which we maintain against some of these risks in amounts that we believe are reasonable, as described above.

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Although we might also have remedies against our contractors or vendors or our joint working interest owners with regard to any losses associated with unintended spills or leaks, the ability to recover from such parties will depend on the indemnity provisions in our contracts as well as the facts and circumstances associated with the causes of such spills or leaks. As a result, our ability to recover associated costs from insurance coverages or other third parties is uncertain.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We use hydraulic fracturing extensively in our operations. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act (SDWA) regulates the underground injection of substances through the Underground Injection Control (UIC) program. While hydraulic fracturing generally is exempt from regulation under the UIC program, Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. In addition, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program as "Class II" UIC wells. Also, in June 2016, EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

In August 2012, the EPA published final regulations under the Clean Air Act (CAA) that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA promulgated New Source Performance Standards establishing emission limits for sulfur dioxide (SO2) and volatile organic compounds (VOCs). The final rules require a 95% reduction in VOCs emitted by mandating the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Until this date, emissions from fractured and refractured gas wells were to be reduced through reduced emission completions or combustion devices. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration and litigation challenging these rules from both industry and the environmental community, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, in May 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the President directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. In June 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. Also, in October 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites. The above standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

In March 2015, the Bureau of Land Management (BLM) published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On March 28, 2017, the President signed an executive order directing the BLM to review the rule and, if appropriate, to initiate a rulemaking to rescind or revise it. In December 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the state of California filed lawsuits challenging the rule rescission. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. In December 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic

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fracturing activities can impact drinking water resources. Also, in February 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These studies, when final and depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Several states and local jurisdictions in which we operate have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas enacted a law requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission adopted rules and regulations applicable to all wells for which the Texas Railroad Commission issues an initial drilling permit on or after February 1, 2012. The regulations require that well operators disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Administration (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, in May 2013, the Texas Railroad Commission issued an updated “well integrity rule,” addressing requirements for drilling, casing and cementing wells, which took effect in January 2014. In addition, Utah’s Division of Oil, Gas and Mining passed a rule in October 2012 requiring all oil and gas operators to disclose the amount and type of chemicals used in hydraulic fracturing operations using the national registry FracFocus.org.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. If new laws or regulations that significantly restrict hydraulic fracturing, such as amendments to the SDWA, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. Until such laws are finalized and implemented, it is not possible to estimate their impact on our business. At this time, no adopted laws or regulations have imposed a material impact on our hydraulic fracturing operations.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission adopted disposal well rule amendments designed to among other things, require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

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Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and gas exploration and development.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws and regulations, it could have a material adverse effect on our business and financial condition.

For example, on December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the Act) that significantly reformed the Internal Revenue Code of 1986, as amended (the Code). Among other changes, the Act (i) permanently reduced the U.S. corporate income tax rate, (ii) repealed the corporate alternative minimum tax, (iii) eliminated the deduction for certain domestic production activities, (iv) imposed new limitations on the utilization of net operating losses generated after 2017, and (v) provided for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The passage of the Act had no effect on our financial statements; however, in past years, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current expensing of intangible drilling and development costs; and
- an extension of the amortization period for certain geological and geophysical expenditures.

While these specific changes are not included in the Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could have a material adverse effect on our business, results of operations and financial condition.

Our debt agreements contain restrictions that limit our flexibility in operating our business.

As of December 31, 2018, our total debt was approximately $4.4 billion, comprised of $8 million in senior secured term loans maturing in 2019, $738 million in senior unsecured notes due in 2020, 2022 and 2023, and $3.6 billion in senior secured notes due in 2024, 2025 and 2026. Our existing debt agreements contain, and any other existing or future indebtedness of ours would likely contain, a number of covenants that impose operating and financial restrictions on us, including restrictions on our and our subsidiaries ability to, among other things:

- incur additional debt, guarantee indebtedness or issue certain preferred shares;
- pay dividends on or make distributions in respect of, or repurchase or redeem, our capital stock or make other restricted payments;
- prepay, redeem or repurchase certain debt;
- make loans or certain investments;
- sell certain assets;
- create liens on certain assets;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- enter into certain transactions with our affiliates;
- alter the businesses we conduct;
- enter into agreements restricting our subsidiaries' ability to pay dividends; and
- designate our subsidiaries as unrestricted subsidiaries.

In addition, the availability of borrowings under the RBL Facility is subject to various financial and non-financial covenants and restrictions. See Part II, Item 8, "Financial Statements and Supplementary Data", Note 8 for additional discussion of the RBL covenants.

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As a result of these covenants, we may be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants under the RBL Facility or any of our other indebtedness could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In the event of any such default, the lenders thereunder:

- will not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable and terminate all commitments to extend further credit; or
- could require us to apply all of our available cash to repay these borrowings.

Such actions by the lenders could cause cross defaults under our other indebtedness. If we were unable to repay those amounts, the lenders or holders under the RBL Facility and our other secured indebtedness could proceed against the collateral granted to them to secure that indebtedness and we could be forced into bankruptcy or liquidation. We pledge a substantial portion of our assets as collateral under the RBL Facility, our senior secured term loans and our secured notes.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions of electronic and information technology systems.

As an oil and natural gas exploration and production company, we use computers and information technology systems to conduct our exploration, development and production activities, and they have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate within our company and with outside business partners. We face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, 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. Cyber-security attacks on businesses have escalated in recent years and are becoming more sophisticated. These attacks may be perpetrated by third parties or insiders. If any of our computer or electronic programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, or if we were subject to a successful cyber-security attack, it could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and/or corruption of data, loss of communication links, inability to find, produce, process and sell oil, natural gas and NGLs, and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. For example, unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could lead to data corruption, communication interruption, or other disruption to our operations and could have a negative impact on our ability to compete for oil and natural gas resources. Although we utilize various procedures and controls to monitor and protect against these threats, as well as to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient to prevent cyber-security breaches. Certain cyber-security incidents, such as surveillance, may remain undetected for an extended period. Any such cyber-security breach or failure could have a material adverse effect on our business, reputation, financial position, results of operations or cash flows.

In addition, a cyber-security attack directed at oil and gas distribution systems, which are necessary to transport and market our production and many of which are controlled by external technologies, could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets, and make it difficult or impossible to accurately account for production and settle transactions. We also have no control over the technology systems of the third parties with whom we do business. Our vendors, midstream providers and other business partners may separately suffer disruptions or cyber-security breaches, which, in turn, could adversely impact our operations and compromise our information. Although we have not suffered material breaches, disruptions or losses related to cyber-security attacks to date, we have experienced and will continue to experience attempts by external parties to penetrate and attack our networks and systems. If we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences, including exposure to potential liability, in addition to the consequences noted above. As cyber-security threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cyber-security or information technology infrastructure vulnerabilities.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Part I, Item 1, "Business", and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our material legal proceedings is included in Part II, Item 8, "Financial Statements and Supplementary Data", Note 9, and is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock started trading on the New York Stock Exchange under the symbol EPE on January 17, 2014. As of February 28, 2019, we had 36 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by Item 301 of Regulation S-K and Article 8 of Regulation S-X.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 8 of this Annual Report on Form 10-K. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in "Risk Factors". Actual results may differ materially from those contained in any forward-looking statements. See "Cautionary Statement Regarding Forward-Looking Statements" in the front of this report. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", "us" and "the Company" refer to EP Energy Corporation and each of its consolidated subsidiaries.

Our Business

Overview. We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We operate through a diverse base of producing assets and are focused on providing returns to our shareholders through the development of our drilling inventory located in three areas: the Eagle Ford Shale in South Texas, Northeastern Utah (NEU), formerly Altamont, in the Uinta basin, and the Permian basin in West Texas, which are further described in Part I, Item I, "Business". Our strategy is to invest in opportunities that provide the highest return across our asset base, continually seek out operating and capital efficiencies, effectively manage costs, and identify accretive acquisition opportunities and divestitures, all with the objective of enhancing our portfolio, growing asset value, improving cash flow and increasing financial flexibility. We evaluate opportunities in our portfolio that are aligned with this strategy and our core competencies and that offer a competitive advantage. In addition to opportunities in our current portfolio, strategic acquisitions of leasehold acreage or acquisitions of producing assets allow us to leverage existing expertise in our areas, balance our exposure to regions, basins and commodities, help us to achieve or enhance risk-adjusted returns competitive with those available in our existing programs and increase our reserves. We also continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term objectives.

Pursuant to our strategy, during 2018, we (i) completed acquisitions expanding our Eagle Ford acreage position by approximately 30 percent in La Salle County, for approximately $277 million and (ii) completed the sale of certain assets in NEU representing approximately 13 percent of our NEU acreage position for approximately $177 million. Additionally, we are also party to certain joint ventures in our asset areas to enhance the development of wells, hold acreage and/or improve near-term economics in our programs. Joint venture funding is approximately 60 percent of the estimated drilling, completion and equipping costs of the wells in exchange for a 50 percent working interest in the joint venture wells. We are the operator of the assets under our joint ventures.

In the Permian, our joint venture partner initially had the option to participate in the development of up to 150 wells in two separate 75 well tranches primarily in Reagan and Crockett counties. We have completed the first tranche of wells. In April 2018, we amended this drilling joint venture agreement to redirect the development area for the second tranche from the Permian to the Eagle Ford with anticipated joint venture investment in the Eagle Ford of $225 million. As of December 31, 2018, we have drilled and completed 44 wells in the Eagle Ford under the amended agreement and expect to drill and complete the remaining wells in 2019. Additionally, subject to certain time limits, we will provide our joint venture partner the option to participate in additional wells that are located within the first and second tranche development areas. For a further discussion on this joint venture, see Part II, Item 8, "Financial Statements and Supplementary Data", Note 11. In NEU, our joint venture partner is participating in the development of 60 wells, and as of December 31, 2018, we have drilled and completed 43 wells under the joint venture agreement.

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Factors Influencing Our Profitability. Our profitability is dependent on the prices we receive for our oil and natural gas, the costs to explore, develop, and produce our oil and natural gas, and the volumes we are able to produce, among other factors. Our profitability is and will continue to be influenced primarily by:

- growing our proved reserve base and production volumes through the successful execution of our drilling programs or through acquisitions;
- finding and producing oil and natural gas at reasonable costs;
- managing operating and capital costs;
- managing commodity price risks on our oil and natural gas production; and
- managing debt levels and related interest costs.

In addition to these factors, our profitability and performance is affected by volatility in the financial and commodity markets. Commodity price changes may affect our future capital spending levels, production rates and/or related operating revenues (net of any associated royalties), levels of proved reserves and development plans, all of which impact performance and profitability.

As a result of the decline in forward prices during the year and the significant reduction to future development capital allocated to the Permian basin, we incurred non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin in the fourth quarter of 2018. In addition to the impairment charges recorded as of December 31, 2018, future commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in a further impairment of the carrying value of our proved and/or unproved properties in the future with our Permian and/or other areas. See Part II, Item 8. "Financial Statements and Supplementary Data", Note 3 and Critical Accounting Estimates for key assumptions and judgments used in this estimation.

As of December 31, 2018, we adjusted our PUD bookings methodology from a five-year to a three-year timeframe as a result of (i) the current economic price environment, (ii) a lower projected capital budget in 2019, and (iii) our available liquidity and access to the capital markets. Based on our anticipated cash flows and capital expenditures, as well as available liquidity and expected access to capital markets transactions, all of our PUD locations are expected to be drilled within a three-year period. Changes in circumstance, including commodity pricing, oilfield service costs, technology, acreage positions and availability of capital and other economic factors may lead to changes in development plans. See Part I, Item 1. "Business" under the heading Oil and Natural Gas Properties for further discussion of our proved reserves.

Derivative Instruments. Our realized prices from the sale of our oil, natural gas and NGLs are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our commodity and (ii) other contractual pricing adjustments contained in our underlying sales contracts. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we enter into financial derivative contracts to reduce the financial impact of downward commodity price movements and unfavorable movements in locational prices. Adjustments to our strategy and the decision to enter into new contracts or positions to alter existing contracts or positions are made based on the goals of the overall company. Because we apply mark-to-market accounting on our derivative contracts, our reported results of operations and financial position can be impacted significantly by commodity price movements from period to period.

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The following table and discussion reflects the contracted volumes and the prices we will receive under derivative contracts we held as of December 31, 2018.

	2019		2020	
	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Oil				
Collars				
Ceiling - WTI	1,640	$ 69.37	—	$ —
Floors - WTI	1,640	$ 57.23	—	$ —
Three Way Collars				
Ceiling - WTI	12,045	$ 66.01	1,830	$ 65.00
Floors - WTI	12,045	$ 55.76	1,830	$ 60.75
Sub-Floor - WTI	12,045	$ 45.00	1,830	$ 45.00
Basis Swaps				
Midland vs. Cushing[2]	1,095	$ (6.47)	—	$ —
Natural Gas				
Fixed Price Swaps	11	$ 3.01	—	$ —
Collars				
Ceiling	15	$ 4.26	—	$ —
Floors	15	$ 2.75	—	$ —
Basis Swaps				
WAHA vs. Henry Hub[3]	7	$ (0.39)	—	$ —

(1) Volumes presented are MBbls for oil and TBtu for natural gas. Prices presented are per Bbl of oil and MMBtu of natural gas.
(2) EP Energy receives Cushing plus the basis spread listed and pays Midland.
(3) EP Energy receives Henry Hub plus the basis spread listed and pays WAHA.

For our three-way collar contracts in the tables above, the sub-floor prices represent the price below which we receive WTI plus a weighted average spread of $10.76 in 2019 and $15.75 in 2020 on the indicated volumes. If WTI is above our sub-floor prices, we receive the noted floor price until WTI exceeds that floor price. Above the floor price, we receive WTI until prices exceed the noted ceiling price in our three-way collars, at which time we receive the fixed ceiling price. As of December 31, 2018, the average forward price of oil was $47.30 per barrel of oil for 2019 and $49.30 per barrel of oil for 2020.

During 2018, we (i) settled commodity index hedges on approximately 89% of our oil production, 78% of our total liquids production and 57% of our natural gas production at average floor prices of $58.47 per barrel of oil, $0.45 per gallon of NGLs and $3.04 per MMBtu of natural gas, respectively. As of December 31, 2018, approximately 100% of our future crude oil contracts allow for upside participation (to a weighted average price of approximately $66.41 per barrel for 2019 and $65.00 per barrel for 2020) while containing certain sub-floor prices (weighted average prices of $45.00 per barrel) that limit the amount of our derivative settlements under these three-way contracts should prices drop below the sub-floor prices. To the extent our oil, natural gas and NGLs production is unhedged, either from a commodity index or locational price perspective, our operating revenues will be impacted from period to period.

For the period from January 1, 2019 through March 13, 2019, we entered into additional derivative contracts on 0.3 MMBbls of 2019 Midland vs. Cushing oil basis swaps with an average price of $(1.50) per barrel of oil and 9.9 MMBbls of 2020 WTI oil three-way collars with a ceiling price of $65.13, a floor price of $55.00 and a sub-floor price of $45.00 per barrel of oil.

Summary of Liquidity and Capital Resources. Our profitability and performance may also be affected by our significant debt and debt service obligations. As of December 31, 2018, our total debt was approximately $4.4 billion, comprised of $8 million in senior secured term loans maturing in 2019, $738 million in senior unsecured notes due in 2020, 2022 and 2023, and $3.6 billion in senior secured notes due in 2024, 2025 and 2026. For the year ended December 31, 2018, we incurred $365 million in interest expense. In May 2020, $182 million of our senior unsecured notes will mature. We project that as of May 2020 we will not have sufficient liquidity available to repay these notes and meet our working capital needs and/or fund our planned capital expenditures. In order to address this projected shortfall in liquidity, we are evaluating certain other sources of incremental liquidity, including issuing additional debt, refinancing our debt and selling assets.

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In 2018, we took a number of steps to improve our asset portfolio and financial flexibility. The actions included (i) completing $277 million in acquisitions in the Eagle Ford (including our largest to date) and divesting of certain assets in NEU for approximately $177 million, (ii) exchanging approximately $1.1 billion of the outstanding amounts of our senior unsecured notes maturing in 2020, 2022 and 2023 for new 2024 senior secured notes, (iii) issuing $1 billion in senior secured notes maturing in 2026 and using the net proceeds to repay in full the outstanding amounts at that time under our RBL Facility and (iv) extending the maturity of our RBL Facility from May 2019 to November 2021. For a further discussion of our liquidity and capital resources, see Liquidity and Capital Resources.

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Production Volumes and Drilling Summary

Production Volumes. Below is a summary of our production volumes for the years ended December 31:

	2018	2017
Equivalent Volumes (MBoe/d)		
Eagle Ford Shale	37.1	35.7
Northeastern Utah	17.1	17.9
Permian	26.5	28.7
Total	80.7	82.3
Oil (MBbls/d)		
Eagle Ford Shale	25.0	22.4
Northeastern Utah	11.7	12.3
Permian	9.1	11.4
Total	45.8	46.1
Natural Gas (MMcf/d)		
Eagle Ford Shale[(1)]	36	39
Northeastern Utah	32	33
Permian	55	55
Total	123	127
NGLs (MBbls/d)		
Eagle Ford Shale	6.1	6.8
Northeastern Utah	—	—
Permian	8.2	8.2
Total	14.3	15.0

(1) Production volume excludes 7 MMcf/d of reinjected gas volumes used in operations during the year ended December 31, 2018.

Drilling Summary. During 2018, we (i) frac'd (wells fracture stimulated) 85 gross wells in Eagle Ford, all of which were completed for a total of 800 net operated wells, (ii) frac'd 27 gross wells in NEU, all of which were completed for a total of 342 net operated wells, and (iii) frac'd 24 gross wells in Permian, all of which were completed for a total of 350 net operated wells. In addition, we recompleted 81 gross wells in NEU during 2018. As of December 31, 2018, we also had a total of 39 gross wells in progress, of which 29 gross wells were drilled, but not completed across our programs.

Production Outlook. For the first quarter of 2019, we anticipate our average daily production volumes to be approximately 72 MBoe/d to 73 MBoe/d, including average daily oil production volumes of approximately 38 MBbls/d to 39 MBbls/d. Future volumes across all our assets will be impacted by the level of natural declines, our drilling plans, and the level and timing of capital spending in each respective area.

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Results of Operations

The information below reflects financial results for EP Energy Corporation for the years ended December 31, 2018 and 2017.

	Year ended December 31,	
	2018	2017
	(in millions)	
Operating revenues:		
Oil	$1,045	$812
Natural gas	75	110
NGLs	120	103
Total physical sales	1,240	1,025
Financial derivatives	84	41
Total operating revenues	1,324	1,066
Operating expenses:		
Oil and natural gas purchases	3	2
Transportation costs	100	115
Lease operating expense	158	163
General and administrative	89	81
Depreciation, depletion and amortization	507	487
Gain on sale of assets	(3)	—
Impairment charges	1,103	2
Exploration and other expense	5	12
Taxes, other than income taxes	77	65
Total operating expenses	2,039	927
Operating (loss) income	(715)	139
Other income	4	—
Gain (loss) on extinguishment/modification of debt	73	(16)
Interest expense	(365)	(326)
Loss before income taxes	(1,003)	(203)
Income tax benefit	—	9
Net loss	$(1,003)	$(194)

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the years ended December 31, 2018 and 2017. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Year ended December 31,	
	2018	2017
	(in millions)	
Operating revenues:		
Oil	$1,045	$812
Natural gas	75	110
NGLs	120	103
Total physical sales	1,240	1,025
Financial derivatives	84	41
Total operating revenues	$1,324	$1,066
Volumes:		
Oil (MBbls)	16,726	16,833
Natural gas (MMcf)	44,913	46,356
NGLs (MBbls)	5,227	5,465
Equivalent volumes (MBoe)	29,439	30,024
Total MBoe/d	80.7	82.3
Prices per unit(1):		
Oil		
Average realized price on physical sales ($/Bbl)(2)	$62.34	$48.23
Average realized price, including financial derivatives ($/Bbl)(2)(3)	$60.37	$53.50
Natural gas		
Average realized price on physical sales ($/Mcf)(2)	$1.66	$2.32
Average realized price, including financial derivatives ($/Mcf)(2)(3)	$1.96	$2.47
NGLs		
Average realized price on physical sales ($/Bbl)	$22.88	$18.87
Average realized price, including financial derivatives ($/Bbl)(3)	$21.79	$18.46

(1) Oil prices for the year ended December 31, 2018 reflect operating revenues for oil reduced by $3 million for oil purchases associated with managing our physical sales. For the year ended December 31, 2017, there were no oil purchases associated with managing our physical oil sales. Natural gas prices for the years ended December 31, 2018 and 2017 reflect operating revenues for natural gas reduced by less than $1 million and $2 million, respectively, for natural gas purchases associated with managing our physical sales.

(2) Changes in realized oil and natural gas prices reflect the effects of unhedged locational or basis differentials, unhedged volumes and contractual deductions between the commodity price index and the actual price at which we sold our oil and natural gas.

(3) The years ended December 31, 2018 and 2017 include approximately $33 million of cash paid and $89 million of cash received, respectively, for the settlement of crude oil derivative contracts. The years ended December 31, 2018 and 2017 include approximately $14 million and $7 million, respectively, of cash received for the settlement of natural gas financial derivatives. The years ended December 31, 2018 and 2017 include approximately $6 million and $3 million of cash paid, respectively, for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the years ended December 31, 2018 and 2017.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. The table below displays the price and volume variances on our physical sales when comparing the years ended December 31, 2018 and 2017.

	Oil	Natural gas	NGLs	Total
	(in millions)			
December 31, 2017 sales	$812	$ 110	$103	$1,025
Change due to prices	238	(31)	21	228
Change due to volumes	(5)	(4)	(4)	(13)
December 31, 2018 sales	$1,045	$ 75	$120	$1,240

Oil sales for the year ended December 31, 2018, compared to the year ended December 31, 2017, increased by $233 million (29%), due primarily to higher oil prices. Higher oil production in Eagle Ford was slightly more than offset by lower oil production in NEU and Permian. In 2018, Eagle Ford oil production volumes increased by 12% (2.6 MBbls/d), while NEU and Permian oil production volumes decreased by 5% (0.6 MBbls/d) and 20% (2.3 MBbls/d), respectively, compared with the year ended December 31, 2017.

Natural gas sales decreased by $35 million (32%) for the year ended December 31, 2018 compared to the year ended December 31, 2017, due primarily to lower natural gas prices in NEU and Permian, and lower natural gas volumes in Eagle Ford.

Our oil, natural gas and NGLs are sold at index prices (WTI, LLS, Henry Hub and Mt. Belvieu) or refiners' posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of fixed or variable contractual deductions, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In NEU, market pricing of our oil is based upon NYMEX based agreements which reflect a locational difference at the wellhead. In the Permian, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. Across all regions, natural gas realized pricing is influenced by factors such as excess royalties paid on flared gas and the percentage of proceeds retained under processing contracts, in addition to the normal seasonal supply and demand influences and those factors discussed above. The table below displays the weighted average differentials and deducts on our oil and natural gas sales on an average NYMEX price.

	Year ended December 31,			
	2018		2017	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(1.81)	$ (1.32)	$(2.92)	$ (0.79)
NYMEX	$64.77	$ 3.09	$50.95	$ 3.11
Net back realization %	97.2 %	57.3 %	94.3 %	74.6 %

The higher oil realization percentage in the year ended December 31, 2018 was primarily a result of the improvement of ICE Brent and LLS basis pricing and physical sales contracts relative to increased NYMEX WTI pricing. The lower natural gas realization percentage in the year ended December 31, 2018 was primarily a result of presenting certain transportation costs as a deduction from natural gas sales in conjunction with adopting Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers in the first quarter of 2018.

NGLs sales increased by $17 million (17%) for the year ended December 31, 2018 compared with 2017. Average realized prices for the year ended December 31, 2018 were higher compared to 2017, due to higher pricing on all liquid components. NGLs pricing is largely tied to crude oil prices.

Future growth in our overall oil, natural gas and NGLs sales (including the impact of financial derivatives) will largely be impacted by commodity pricing, our level of hedging, our ability to maintain or grow oil volumes and by the location of our production and the nature of our sales contracts. For further discussion on our derivative instruments, see Our Business and Liquidity and Capital Resources.

Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the years ended December 31, 2018 and 2017, we recorded derivative gains of $84 million and $41 million, respectively.

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Operating Expenses

The tables below provide our operating expenses, volumes and operating expenses per unit for each of the periods presented:

	Year ended December 31,			
	2018		2017	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ 3	$ 0.10	$ 2	$ 0.07
Transportation costs	100	3.41	115	3.83
Lease operating expense(2)	158	5.35	163	5.42
General and administrative(3)	89	3.03	81	2.69
Depreciation, depletion and amortization	507	17.23	487	16.22
Gain on sale of assets	(3)	(0.13)	—	—
Impairment charges	1,103	37.47	2	0.04
Exploration and other expense	5	0.18	12	0.40
Taxes, other than income taxes	77	2.61	65	2.19
Total operating expenses	$ 2,039	$ 69.25	$ 927	$ 30.86
Total equivalent volumes (MBoe)	29,439		30,024	

(1) Per unit costs are based on actual amounts rather than the rounded totals presented.

(2) Includes approximately $2 million for the year ended December 31, 2018 or $0.07 per Boe of adjustments under a joint venture agreement.

(3) For the year ended December 31, 2018, amount includes approximately $9 million or $0.32 per Boe of transition and severance costs related to workforce reductions, $13 million or $0.47 per Boe of non-cash compensation expense (net of forfeitures). For the year ended December 31, 2017, amount includes approximately $19 million or $0.64 per Boe of transition and severance costs related to workforce reductions, $(22) million or $(0.75) per Boe of non-cash compensation expense (net of forfeitures) and $5 million or $0.18 per Boe of fees paid to our Sponsors.

Transportation costs. Transportation costs for the year ended December 31, 2018 decreased by $15 million as compared to 2017 primarily as a result of presenting certain transportation costs as a deduction from natural gas sales in conjunction with adopting ASU No. 2014-09, Revenue from Contracts with Customers in the first quarter of 2018.

Lease operating expense. Lease operating expense for the year ended December 31, 2018 decreased by $5 million compared to 2017. The decrease in 2018 compared to 2017 is due to lower maintenance and repair costs in all areas, partially offset by higher compression, disposal, chemical, power and fuel costs primarily in Eagle Ford. In addition, lease operating expense for the year ended December 31, 2018 includes approximately $2 million in adjustments under a joint venture agreement.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2018 increased by $8 million compared to 2017 primarily due to forfeitures in 2017 of approximately $33 million of long-term incentive awards associated with the change in executive management. In addition, when comparing the year ended December 31, 2018 to 2017, we recorded lower payroll and severance expense of $24 million due to staff reductions in 2017 and 2018.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the year ended December 31, 2018 increased by $20 million compared to 2017 due to increased capital spending and slightly lower production volumes when compared to the same periods in 2017. Our depreciation, depletion and amortization rate in the future will be impacted by the level and timing of capital spending, overall cost of capital and the level and type of reserves recorded on completed projects. Our average depreciation, depletion and amortization costs per unit for the year-to-date periods were:

	Year ended December 31,	
	2018	2017
Depreciation, depletion and amortization ($/Boe)	$17.23	$16.22

Impairment charges. For the year ended December 31, 2018, we recorded non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin as a result of the decline in commodity prices and the significant reduction in future development capital allocated to the Permian. See Part II, Item 8. Financial Statements, Note 3, for more information on impairment.

Exploration and other expense. Exploration and other expense for the year ended December 31, 2018 decreased by $7 million from 2017 due to lower amortization of unproved leasehold costs reflecting the sale of certain assets in NEU in early 2018 in addition to recording certain expenses in 2018 associated with contractual commitments.

Taxes, other than income taxes. Taxes, other than income taxes for the year ended December 31, 2018 increased by $12 million from 2017. The increase in 2018 compared to 2017 is primarily due to an increase in severance taxes as a result of higher oil and NGL prices.

Other Income Statement Items.

Gain (loss) on extinguishment/modification of debt. During the year ended December 31, 2018, we recorded a total gain on extinguishment of debt of $73 million primarily due to (i) exchanging certain senior unsecured notes for $1,092 million in new senior secured notes and (ii) repurchasing a portion of our senior unsecured notes due 2020, 2022 and 2023.

For the year ended December 31, 2017, we recorded a total loss on extinguishment of debt of $16 million as a result of (i) repurchasing senior unsecured notes due 2020 and 2023 and (ii) retiring our senior secured term loans due 2021 and a portion of our 9.375% senior notes due 2020. See Part II, Item 8, Financial Statements, Note 8 for more information on our long-term debt.

Interest expense. Interest expense for the year ended December 31, 2018 increased by $39 million compared to the same period in 2017 due primarily to the issuance of senior secured notes due 2026, partially offset by (i) lower average borrowings under our RBL Facility during the year ended December 31, 2018, (ii) the impact of the retirement of certain debt obligations in 2017 and (iii) the repurchases of a portion of our senior unsecured notes due 2020, 2022 and 2023.

Income taxes. Our effective tax rates for the years ended December 31, 2018 and 2017 were 0% and 4.5%, which differed from the statutory rates of 21% and 35%, respectively, primarily due to recording a full valuation allowance on our net deferred tax assets. The effective tax rates for 2018 and 2017 are also impacted by recording non-deductible compensation expenses, and in 2017 also reflect recording a current income tax benefit and related receivable for the recovery of previously paid alternative minimum taxes based on a change in our tax depreciation elections. For additional details on our income taxes, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 4.

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Supplemental Non-GAAP Measures

We use the non-GAAP measures "EBITDAX" and "Adjusted EBITDAX" as supplemental measures. We believe these supplemental measures provide meaningful information to our investors. We define EBITDAX as net income (loss) plus interest and debt expense, income taxes, depreciation, depletion and amortization and exploration expense. Adjusted EBITDAX is defined as EBITDAX, adjusted as applicable in the relevant period for the net change in the fair value of derivatives (mark-to-market effects of financial derivatives, net of cash settlements and cash premiums related to these derivatives), the non-cash portion of compensation expense (which represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under these plans), transition, severance and other costs that affect comparability, fees paid to our Sponsors, gains and losses on sale of assets, gains and losses on extinguishment/modification of debt and impairment charges.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt, adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business without regard to financing methods and capital structure, (iii) for evaluating our performance relative to our peers, (iv) to measure our liquidity (before cash capital requirements and working capital needs) and (v) to provide supplemental information about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDAX and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with GAAP.

Below is a reconciliation of our consolidated net income (loss) to EBITDAX and Adjusted EBITDAX:

	Year ended December 31,	
	2018	2017
	(in millions)	
Net loss	$(1,003)	$(194)
Income tax benefit	—	(9)
Interest expense, net of capitalized interest	365	326
Depreciation, depletion and amortization	507	487
Exploration expense	4	9
EBITDAX	(127)	619
Mark-to-market on financial derivatives[(1)]	(84)	(41)
Cash settlements and cash premiums on financial derivatives[(2)]	(25)	93
Non-cash portion of compensation expense[(3)]	13	(22)
Transition, severance and other costs[(4)]	9	19
Fees paid to Sponsors	—	5
Gain on sale of assets	(3)	—
(Gain) loss on extinguishment/modification of debt	(73)	16
Impairment charges[(5)]	1,103	2
Adjusted EBITDAX	$813	$691

(1) Represents the income statement impact of financial derivatives.

(2) Represents actual cash settlements related to financial derivatives. No cash premiums were received or paid for the years ended December 31, 2018 and 2017.

(3) There were no cash payments for the year ended December 31, 2018. For the year ended December 31, 2017, the non-cash portion of compensation expense (net of forfeitures) includes cash payments of approximately $4 million.

(4) Reflects transition and severance costs related to workforce reductions.

(5) Represents non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin as a result of the decline in commodity prices and the significant reduction in future development capital allocated to the Permian.

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Liquidity and Capital Resources

Overview. Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility and our primary uses of cash are capital expenditures, debt service, including interest, and working capital requirements. As of December 31, 2018, our available liquidity was approximately $537 million.

During 2018, we took steps to improve our financial flexibility, which included (i) exchanging approximately $1,147 million of our senior unsecured notes maturing in May 2020, September 2022 and June 2023 for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million, (ii) issuing $1 billion of 7.75% senior secured notes, which mature in 2026, and using the net proceeds to repay in full the outstanding amounts at that time under our RBL Facility, (iii) extending the maturity of our RBL Facility from May 2019 to November 2021, and (iv) reaffirming our RBL borrowing base at $1.36 billion (with commitments remaining at $629 million). While overall liquidity declined approximately $700 million due to the reduction in RBL commitments to $629 million from approximately $1.36 billion, these refinancing activities provided us immediate access to the full $629 million of capacity under our RBL Facility (of which approximately $510 million of capacity was available as of December 31, 2018) and an incremental $80 million of cash for capital expenditure and working capital needs while extending the maturity of our RBL Facility until 2021 as noted above. In 2018 and into 2019, we also utilized available liquidity to repurchase $134 million in aggregate principal amount of our 2020, 2022 and 2023 senior unsecured notes for approximately $89 million in cash. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets, or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. Conversely, future acquisitions, reserve additions and higher prices may have the effect of increasing our borrowing base.

Debt Maturities and Covenants As of December 31, 2018, our total debt was approximately $4.4 billion, comprised of $8 million in senior secured term loans maturing in 2019, $738 million in senior unsecured notes due in 2020, 2022 and 2023, and $3.6 billion in senior secured notes due in 2024, 2025 and 2026. Our most restrictive financial debt covenants (which were modified and/or extended in 2018) include a requirement to maintain a first lien debt to EBITDAX ratio of 2.25 to 1.00 and a current ratio (as defined in the RBL Facility) to be not less than 1.00 to 1.00. As of December 31, 2018, we were in compliance with our debt covenants. For additional details on our long-term debt, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 8.

Capital Expenditures. Our capital expenditures and average drilling rigs for the twelve months ended December 31, 2018 were:

	Capital Expenditures[(1)] (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 425	3.0
Northeastern Utah	120	2.0
Permian	99	0.3
Total	$ 644	5.3
Acquisition and other capital[(2)]	$ 340	
Total capital expenditures	$ 984	

(1) Represents accrual-based capital expenditures.

(2) Reflects cash paid for acquisitions (including a deposit made in December 2017) and capital adjustments under a joint venture agreement.

During 2018, we completed acquisitions of additional working interests in certain producing properties in the Eagle Ford for approximately $277 million, including our largest acquisition to date of $246 million, and sold certain assets in NEU for approximately $177 million.

Outlook. In the first quarter of 2019, we expect to spend approximately $160 million to $170 million in capital (excluding acquisition capital) in our programs, with approximately 85% allocated to the Eagle Ford Shale and approximately 15% allocated to NEU. Based upon our current price and cost assumptions and our hedge program, we believe that our current capital program will exceed our estimated operating cash flows after interest payments. However, we believe the borrowing capacity under our RBL Facility and expected cash flows from our operations will be sufficient to fund our capital program and meet current obligations and projected working capital requirements through the next twelve months.

In May 2020, $182 million of our senior unsecured notes will mature. Based on our current forecasted EBITDAX

(assuming $55/barrel of oil), cash on hand, and remaining RBL capacity, we project that as of May 2020, we will not have
sufficient liquidity available to repay these notes and meet our working capital needs and/or fund our planned capital expenditures. In order to address this projected shortfall in liquidity, we are evaluating certain other sources of incremental
liquidity including additional debt issuances or refinancings, and asset sales. If we are not successful in obtaining the necessary additional liquidity, whether through executing one or more of these potential actions or otherwise, and/or if commodity prices do not appreciably increase prior to the filing date of our Quarterly Report on Form 10-Q for the period ending March 31, 2019, we would expect to disclose in that Quarterly Report that, in the absence of executing on these potential actions or commodity prices appreciably increasing, there would be substantial doubt that we would be able to continue as a going concern beginning in May 2020. In addition, should we be required to include a going concern disclosure in our year-end audited financial statements (in the absence of a waiver or other suitable relief), the disclosure would result in an event of default under the RBL Facility, after which the lenders thereunder could accelerate the outstanding indebtedness. An event of default under our RBL Facility could trigger cross-defaults under our other debt agreements, including our senior secured term loan and our senior secured and unsecured notes, which could also result in the acceleration of those obligations by the lenders thereunder. Even if we are able to implement such strategic alternatives, they may be insufficient to meet our debt and other obligations over the longer term. Furthermore, such strategic alternatives may adversely affect our creditors or our existing stockholders, potentially resulting in a reduction in the value of their investment or the loss of all or substantially all of their investment in us.

We will continue to be aggressive in managing our cost structure and in turn, our liquidity, to meet our capital and operating needs. Additionally, we continually monitor the capital markets and will be opportunistic in taking certain future actions to manage our capital structure including, where possible and allowed under our debt agreements (i) acquiring additional amounts of our outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of our debtholders and/or (ii) issuing additional secured debt as permitted under our debt agreements, although there is no assurance we would do so.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all, or (iii) obtain additional capital on acceptable terms or at all to fund our capital programs or any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic and industry conditions, many of which are volatile and beyond our control. Should commodity prices decline from current levels, or we experience disruptions in the financial markets impacting our cost of capital, it is possible that additional adjustments to our plan and outlook may occur based on market conditions and the needs of the Company at that time, which could include selling assets, seeking additional partners to develop our assets, issuing equity, and/or further reducing our planned capital spending program.

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Overview of Cash Flow Activities. Our cash flows are summarized as follows:

	Year ended December 31,	
	2018	2017
	(in millions)	
Cash Inflows		
Operating activities		
Net loss	$(1,003)	$(194)
Impairment charges	1,103	2
Gain on sale of assets	(3)	—
(Gain) loss on extinguishment/modification of debt	(73)	16
Other income adjustments	537	487
Change in assets and liabilities	(139)	64
Total cash flow from operations	$422	$375
Investing activities		
Proceeds from the sale of assets	$192	$—
Deposit received in advance of divestiture	—	18
Cash inflows from investing activities	$192	$18
Financing activities		
Proceeds from issuance of long-term debt	2,090	1,930
Cash inflows from financing activities	$2,090	$1,930
Total cash inflows	$2,704	$2,323
Cash Outflows		
Investing activities		
Cash paid for capital expenditures	$690	$541
Cash paid for acquisitions	292	29
Deposit paid in advance of acquisition	—	25
Cash outflows from investing activities	$982	$595
Financing activities		
Repayments and repurchases of long-term debt	$1,654	$1,679
Fees/costs on debt exchange	62	—
Debt issue costs	22	21
Other	2	3
Cash outflows from financing activities	$1,740	$1,703
Total cash outflows	$2,722	$2,298
Net change in cash, cash equivalents and restricted cash	$(18)	$25

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 9.

Off-Balance Sheet Arrangements

We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. We do not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial condition or results of operations.

Critical Accounting Estimates

Our significant accounting policies are described in Part II, Item 8, "Financial Statements and Supplementary Data", Note 1 of our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates:

Accounting for Oil and Natural Gas Producing Activities. We apply the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, non-drilling exploratory costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred while acquisition costs, development costs and the costs of drilling and completing wells are capitalized. If a well is exploratory in nature, such costs are capitalized, pending the determination of proved oil and natural gas reserves. As a result, at any point in time, we may have capitalized costs on our consolidated balance sheet associated with exploratory wells that may be charged to exploration expense in a future period. Costs of drilling exploratory wells that do not result in proved reserves are expensed. Under the successful efforts method, we also capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. Depreciation, depletion, amortization and the impairment of oil and natural gas properties is calculated on a depletable unit basis based on estimates of proved quantities of proved oil and natural gas reserves. Revisions to these estimates can alter our depletion rates in the future and affect our future depletion expense or assessment of impairment.

We evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as a significant decline in forward commodity prices or change in development plans, among other items) to determine if impairment of such properties has occurred. Our evaluation of whether costs are recoverable is made based on common geological structure or stratigraphic conditions (for example, we evaluate proved property for impairment separately for each of our operating areas), and the evaluation considers estimated future cash flows for all proved developed (producing and non-producing), proved undeveloped reserves and risk-weighted non-proved reserves in comparison to the carrying amount of the proved properties. Important assumptions in the determination of these cash flows are estimates of future oil and gas production, estimated forward commodity prices as of the date of the estimate, adjusted for geographical location and contractual and quality differentials and estimates of future operating and development costs. If the carrying amount of a property exceeds the estimated undiscounted future cash flows of its reserves, the carrying amount is reduced to estimated fair value through a charge to income. Fair value is calculated by discounting those estimated future cash flows using a risk-adjusted discount rate. The discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Each of these estimates involves a high degree of judgment.

Capitalized costs associated with unproved properties (e.g., leasehold acquisition costs associated with non-producing areas) are also assessed for impairment based on estimated drilling plans and capital expenditures, which may also change relative to forward commodity prices and/or potential lease expirations. Generally, economic recovery of unproved reserves in non-producing areas are not yet supported by actual production or conclusive formation tests, but must be confirmed by continued exploration and development activities. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g., a low oil price environment), the availability of oilfield services and the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives.

During the year ended December 31, 2018, we recorded non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin due to the decline in commodity prices during the year as well as the significant reduction in future development capital allocated to the Permian. As of December 31, 2018, our remaining net capitalized costs related to proved properties were approximately $1,815 million in Eagle Ford, $1,137 million in NEU, and $785 million in the Permian basin.

The proved oil and gas reserve estimates as of December 31, 2018 have been prepared by Ryder Scott Company, L.P. (Ryder Scott), our independent third party reserve engineers. Estimates of proved reserves reflect quantities of oil, natural gas and NGLs, which geological and engineering data demonstrate, with reasonable certainty, will be recoverable in future years from known reservoirs under existing economic conditions. These estimates of proved oil and natural gas reserves primarily impact our property, plant and equipment amounts on our balance sheets and the depreciation, depletion and amortization amounts, including any impairment charges, on our consolidated income statements, among other items. The process of estimating oil and natural gas reserves is complex and requires significant judgment to evaluate all available geological, geophysical engineering and economic data. Significant assumptions used in the proved oil and gas reserve estimates are assessed by both Ryder Scott and our internal reserve team. All reserve reports prepared by Ryder Scott were reviewed by our internal reserve and management teams. Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered.

As of December 31, 2018, 28% of our total proved reserves were undeveloped and 2% were developed, but non-producing. The data for a given field may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates. As a result, material revisions to existing reserve estimates occur from time to time. For example, in 2018 we adjusted our PUD booking methodology from a five-year to a three-year timeframe. Given our current financial situation with limited available liquidity, our PUD reserves of 91 MMBoe at December 31, 2018 reflect 64 MMBoe of negative adjustments as a result of determining our PUDs using a three-year timeframe instead of a five-year timeframe. See Part I, Item 1. "Business" under the heading Oil and Natural Gas Properties for further discussion on our proved reserves.

Deferred Taxes and Valuation Allowances. We record deferred income tax assets and liabilities reflecting the tax consequences of differences between the financial statement carrying value of assets and liabilities and the tax basis of those assets and liabilities. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Our deferred tax assets and liabilities reflect our conclusions about which positions are more likely than not to be sustained if they are audited by taxing authorities.

We assess the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of existing deferred tax assets. When it is more likely than not that we will not be able to realize all or a portion of such asset, we record a valuation allowance. Based upon the evaluation of the available evidence, we maintained a valuation allowance against our net deferred tax assets of $857 million as of December 31, 2018. We evaluate our valuation allowances each reporting period and the level of such allowance will change as our deferred tax balances change. Key estimates and assumptions include expectations of future taxable income and the ability and our intent to undertake transactions that will allow us to realize the asset, all of which involve judgment. Changes in these estimates or assumptions can have a significant effect on our operating results.

ITEM 7A. Qualitative and Quantitative Disclosures About Market Risk

We are exposed to market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

Commodity Price Risk

- changes in oil, natural gas and NGLs prices impact the amounts at which we sell our production and affect the fair value of our oil and natural gas derivative contracts; and
- changes in locational price differences also affect amounts at which we sell our oil, natural gas and NGLs production, and the fair values of any related derivative products.

Interest Rate Risk

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changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of fixed-rate debt; and

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- changes in interest rates used to discount liabilities result in higher or lower recorded amount of liabilities and accretion expense over time.

Risk Management Activities

Where practical, we manage commodity price risks by entering into contracts involving physical or financial settlement that attempt to limit exposure related to future market movements on our cash flows. The timing and extent of our risk management activities are based on a number of factors, including our market outlook, risk tolerance and liquidity. Our risk management activities typically involve the use of the following types of contracts:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- option contracts, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;
- swap contracts, which require payments to or from counterparties based upon the differential between two prices or rates for a predetermined contractual (notional) quantity; and
- structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we use in our risk management activities qualify as derivative financial instruments. A discussion of our accounting policies for derivative instruments is included in Part II Item 8, "Financial Statements and Supplementary Data", Notes 1 and 6.

For information regarding changes in commodity prices during 2018, please see Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”.

Commodity Price Risk

Oil, Natural Gas and NGLs Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of derivative oil and natural gas swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives changes. Our derivatives do not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risks on our remaining forecasted production.

Sensitivity Analysis. The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at December 31, 2018:

		Oil and Natural Gas Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(in millions)			
Price impact(1)	$ 114	$ 71	$ (43)	$ 151	$ 37

		Oil and Natural Gas Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(in millions)			
Discount Rate(2)	$ 114	$ 114	$ —	$ 115	$ 1
Credit rate(3)	$ 114	$ 113	$ (1)	$ 115	$ 1

(1) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from changes in oil and natural gas prices.

(2) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in the discount rates we used to determine the fair value of our derivatives.

(3) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in credit risk of our counterparties

Interest Rate Risk

Certain of our debt agreements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average effective interest rates on our long-term interest-bearing debt by expected maturity date as well as the total fair value of the debt. The fair value of our long-term debt has been estimated primarily based on quoted market prices for the same or similar issues.

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	December 31, 2018								December 31, 2017	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2019	2020	2021	2022	2023	Thereafter	Total	Value	Amounts	Value
					(in millions)					
Fixed rate long-term debt	$50	$182	$—	$182	$324	$3,592	$4,330	$2,468	$3,469	$2,644
Average interest rate	8.2 %	8.2 %	8.2 %	8.2 %	8.3 %	7.9 %				
Variable rate long-term debt	$8	$—	$100	$—	$—	$—	$108	$108	$624	$623
Average interest rate	7.0 %	7.0 %	7.0 %	— %	— %	— %				

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data

Schedules

All financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the financial statements or related notes thereto.

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by SEC rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2018. In making this assessment, we used the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2018. The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by Ernst & Young LLP, an independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, as stated in their report included herein.

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Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
EP Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EP Energy Corporation (the Company) as of December 31, 2018 and 2017, the related consolidated statements of income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 18, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2006.

Houston, Texas
March 18, 2019

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Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
EP Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited EP Energy Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, EP Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of income, cash flows and changes in equity for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 18, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
March 18, 2019

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,	
	2018	2017
Operating revenues		
Oil	$1,045	$812
Natural gas	75	110
NGLs	120	103
Financial derivatives	84	41
Total operating revenues	1,324	1,066
Operating expenses		
Oil and natural gas purchases	3	2
Transportation costs	100	115
Lease operating expense	158	163
General and administrative	89	81
Depreciation, depletion and amortization	507	487
Gain on sale of assets	(3)	—
Impairment charges	1,103	2
Exploration and other expense	5	12
Taxes, other than income taxes	77	65
Total operating expenses	2,039	927
Operating (loss) income	(715)	139
Other income	4	—
Gain (loss) on extinguishment/modification of debt	73	(16)
Interest expense	(365)	(326)
Loss before income taxes	(1,003)	(203)
Income tax benefit	—	9
Net loss	$(1,003)	$(194)
Basic and diluted net income (loss) per common share		
Net loss	$(4.05)	$(0.79)
Basic and diluted weighted average common shares outstanding	248	246

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 27	$ 27
Restricted cash	—	18
Accounts receivable		
Customer, net of allowance of less than $1 in 2018 and 2017	164	158
Other, net of allowance of $1 in 2018 and 2017	66	13
Income tax receivable	—	9
Materials and supplies	22	16
Derivative instruments	101	18
Assets held for sale	—	172
Prepaid assets	5	35
Total current assets	385	466
Property, plant and equipment, at cost		
Oil and natural gas properties	7,344	7,532
Other property, plant and equipment	81	69
	7,425	7,601
Less accumulated depreciation, depletion and amortization	3,651	3,179
Total property, plant and equipment, net	3,774	4,422
Other assets		
Derivative instruments	13	4
Unamortized debt issue costs on revolving credit facility	8	6
Other	1	2
	22	12
Total assets	$ 4,181	$ 4,900

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 115	$ 88
Other	111	158
Derivative instruments	—	17
Accrued interest	70	62
Liabilities related to assets held for sale	—	2
Short-term debt, net of debt issue costs	58	21
Other accrued liabilities	86	100
Total current liabilities	440	448
Long-term debt, net of debt issue costs	4,285	4,022
Other long-term liabilities		
Asset retirement obligations	39	33
Other	16	5
Total non-current liabilities	4,340	4,060
Commitments and contingencies (Note 9)		
Stockholders’ equity		
Class A shares, $0.01 par value; 550 million shares authorized; 256 million shares issued and outstanding at December 31, 2018; 550 million shares authorized; 252 million shares issued and outstanding at December 31, 2017	3	3
Class B shares, $0.01 par value; less than one million shares authorized, issued and outstanding at December 31, 2018 and December 31, 2017	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Treasury stock (at cost); less than one million shares at December 31, 2018 and December 31, 2017	(1)	(3)
Additional paid-in capital	3,536	3,526
Accumulated deficit	(4,137)	(3,134)
Total stockholders’ equity	(599)	392
Total liabilities and equity	$ 4,181	$ 4,900

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash flows from operating activities		
Net loss	$(1,003)	$(194)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	507	487
Gain on sale of assets	(3)	—
Impairment charges	1,103	2
(Gain) loss on extinguishment/modification of debt	(73)	16
Other non-cash income items	30	—
Asset and liability changes		
Accounts receivable	(56)	(22)
Accounts payable	6	55
Derivative instruments	(109)	52
Accrued interest	8	19
Other asset changes	8	(16)
Other liability changes	4	(24)
Net cash provided by operating activities	422	375
Cash flows from investing activities		
Cash paid for capital expenditures	(690)	(541)
Proceeds from the sale of assets	192	—
Cash paid for acquisitions	(292)	(29)
Deposit paid in advance of acquisition	—	(25)
Deposit received in advance of divestiture	—	18
Net cash used in investing activities	(790)	(577)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	2,090	1,930
Repayments and repurchases of long-term debt	(1,654)	(1,679)
Fees/costs on debt exchange	(62)	—
Debt issue costs	(22)	(21)
Other	(2)	(3)
Net cash provided by financing activities	350	227
Change in cash, cash equivalents and restricted cash	(18)	25
Cash, cash equivalents and restricted cash - beginning of period	45	20
Cash, cash equivalents and restricted cash - end of period	$27	$45
Supplemental cash flow information		
Interest paid, net of amounts capitalized	$337	$291
Income tax (refunds) payments	(9)	1

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(In millions)

	Class A Stock		Class B Stock		Treasury Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total
	Shares	Amount	Shares	Amount				
Balance at December 31, 2016	251	$ 2	0.8	$ —	$ (3)	$ 3,546	$ (2,939)	$ 606
Cumulative effect of accounting change	—	—	—	—	—	1	(1)	—
Balance at January 1, 2017	251	$ 2	0.8	—	$ (3)	$ 3,547	$ (2,940)	$ 606
Share-based compensation	1	1	(0.5)	—	—	(21)	—	(20)
Net loss	—	—	—	—	—	—	(194)	(194)
Balance at December 31, 2017	252	$ 3	0.3	—	$ (3)	$ 3,526	$ (3,134)	$ 392
Share-based compensation	4	—	—	—	2	10	—	12
Net loss	—	—	—	—	—	—	(1,003)	(1,003)
Balance at December 31, 2018	256	$ 3	0.3	$ —	$ (1)	$ 3,536	$ (4,137)	$ (599)

See accompanying notes.

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EP ENERGY CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
1. Basis of Presentation and Significant Accounting Policies
Basis of Presentation and Consolidation
Our consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and include the accounts of all consolidated subsidiaries after the elimination of all significant intercompany accounts and transactions.
We consolidate entities when we have the ability to control the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment.
We are engaged in the exploration for and the acquisition, development, and production of oil, natural gas and NGLs in the United States. Our oil and natural gas properties are managed as a single operating segment rather than through discrete operating segments or business units. We track basic operational data by area and allocate capital resources on a project-by-project basis across our entire asset base without regard to individual areas. We assess financial performance as a single enterprise and not on a geographical area basis.
New Accounting Pronouncements Issued But Not Yet Adopted
The following accounting standards have been issued but not yet been adopted.
Leases. In February 2016, the Financial Accounting Standards Board (FASB) issued ASU No. 2016-02, Leases, which requires lessees to recognize right-of-use assets and liabilities on the balance sheet and disclose key information about leasing arrangements. Adoption of this standard is required beginning in the first quarter of 2019 and we anticipate adopting this standard on a modified retrospective basis, recognizing a cumulative-effect adjustment to the opening balance of retained earnings, if any, upon adoption. In addition, we plan to make certain permitted elections upon adoption around lease classification of contracts and land easements existing prior to the adoption date and not recognizing short-term leases on our balance sheet. We do not currently anticipate our adoption of this standard will have a material impact on our financial statements, business processes and/or related controls.

Significant Accounting Policies
Use of Estimates
The preparation of our financial statements requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.
Revenue Recognition
Our revenues are generated primarily through the physical sale of oil, natural gas and NGLs to third party customers at spot or market prices under both short and long-term contracts. We recognize revenue upon satisfaction of our contractual performance obligation requiring us to deliver oil, natural gas and NGLs to a delivery point. Our performance obligation is satisfied upon transfer of control of the commodity to the customer. Transfer of control varies depending on the product and delivery method, but typically occurs when delivery and passage of title and risk of loss have occurred at a pipeline or gathering line delivery point interconnect when delivered via pipeline or at the wellhead or tank battery to purchasers who transport the oil via truck. Realized prices for each barrel of oil, MMcf of natural gas or MMBtu of NGLs are based upon index prices (WTI, LLS, Henry Hub and Mt. Belvieu) or refiners' posted prices at various delivery points across our producing basins. Realized transaction prices received (not considering the effects of hedges) are generally less than the stated index price as a result of contractual deductions, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade.

Revenue is recorded net of any royalty interests or other profit interests in the produced product. Revenues related to products delivered, but not yet billed, are estimated each month. These estimates are based on contract data, commodity prices and preliminary throughput and allocation measurements. When actual sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability.

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Costs associated with the transportation and delivery of production between the wellhead and its intended sale location are generally included in transportation costs. We also purchase and sell oil and natural gas on a monthly basis to manage our overall oil and natural gas production and sales. These transactions are undertaken to optimize prices we receive for our oil and natural gas, to physically move oil and gas to its intended sales point, or to manage firm transportation agreements. Revenue related to these transactions are recorded in oil and natural gas sales in operating revenues and associated purchases reflected in oil and natural gas purchases in operating expenses in our consolidated income statements.

For the years ended December 31, 2018 and 2017, we had three and two customers, respectively, that individually accounted for 10 percent or more of our total revenues. The loss of any one customer would not have an adverse effect on our ability to sell our oil, natural gas and NGLs production.

While most of our physical production is priced off of market indices, we actively manage the volatility of market pricing through our risk management program whereby we enter into financial derivatives contracts. All of our derivatives are marked-to-market each period. The change in the fair value of our commodity-based derivatives, as well as any realized amounts, are reflected in operating revenues as financial derivative revenues (see Derivatives below and Note 6).

Cash and Cash Equivalents and Restricted Cash

We consider short-term investments with an original maturity of less than three months to be cash equivalents. As of December 31, 2018, we had no restricted cash. As of December 31, 2017, we had $18 million in restricted cash reflecting a deposit received in advance of the divestiture of certain assets.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances with other parties if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method.

Oil and Natural Gas Properties

We account for oil and natural gas properties in accordance with the successful efforts method of accounting for oil and natural gas exploration and development activities.

Under the successful efforts method, we capitalize (i) lease acquisition costs, all development costs and exploratory drilling costs until results are determined, (ii) certain internal costs directly identified with the acquisition, successful drilling of exploratory wells and development activities, and (iii) interest costs related to financing oil and natural gas projects actively being developed until the projects are evaluated or substantially complete and ready for their intended use if the projects were evaluated as successful. Non-drilling exploratory costs, including certain geological and geophysical costs such as seismic costs and delay rentals, are expensed as incurred.

We provide for depreciation, depletion, and amortization on the basis of common geological structure or stratigraphic conditions applied to total capitalized costs, plus future abandonment costs, net of salvage value, using the unit of production method. Lease acquisition costs are amortized over total proved reserves, while other exploratory drilling and all developmental costs are amortized over total proved developed reserves.

We evaluate capitalized costs related to proved properties upon a triggering event to determine if impairment of such properties is necessary. Our evaluation of recoverability is made on the basis of common geological structure or stratigraphic conditions and considers estimated future cash flows primarily from all proved developed (producing and non-producing) and proved undeveloped reserves in comparison to the carrying amount of the proved properties. Estimated future cash flows are determined based on estimates of future oil and gas production, estimated or published commodity prices as of the date of the estimate, adjusted for geographical location, contractual and quality price differentials, and estimates of future operating and development costs. If the carrying amount of a property exceeds these estimated undiscounted future cash flows, the carrying amount is reduced to its estimated fair value through a charge to income. Fair value is calculated by discounting the estimated future cash flows using a risk-adjusted discount rate. This discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Leasehold acquisition costs associated with non-producing areas are also assessed for impairment based on our estimated drilling plans and anticipated capital expenditures related to potential lease expirations.

Property, Plant and Equipment (Other than Oil and Natural Gas Properties)

Our property, plant and equipment, other than our assets accounted for under the successful efforts method, are recorded at their original cost of construction or, upon acquisition, at the fair value of the assets acquired. We capitalize the major units of property replacements or improvements and expense minor items. We depreciate our non-oil and natural gas property, plant and equipment using the straight-line method over the useful lives of the assets which range from four to 15 years.

Accounting for Asset Retirement Obligations

We record a liability for legal obligations associated with the replacement, removal or retirement of our long-lived assets in the period the obligation is incurred and is estimable. Our asset retirement liabilities are initially recorded at their estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the asset to which that liability relates. An ongoing expense is recognized for changes in the value of the liability as a result of the passage of time, which we record as depreciation, depletion and amortization expense in our consolidated income statements.

Accounting for Long-Term Incentive Compensation

We measure the cost of long-term incentive compensation based on the fair value of the award on the day it is granted. Awards issued under our incentive compensation programs are recognized as either equity awards or liability awards based on their characteristics. Expense is recognized in our consolidated financial statements as general and administrative expense over the period of service required by the award. As a result of adopting ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting, as of January 1, 2017, we recorded a cumulative adjustment of approximately $1 million to the opening balance of retained earnings related to our election to begin accounting for forfeitures in compensation cost when they occur, rather than estimating them over the service period. See Note 10 for further discussion of our long-term incentive compensation.

Environmental Costs, Legal and Other Contingencies

Environmental Costs. We record environmental liabilities at their undiscounted amounts on our consolidated balance sheet in other current and long-term liabilities when we assess that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on current available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and expense costs that do not in general and administrative expense.

We evaluate any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the creditworthiness or solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our consolidated balance sheet.

Legal and Other Contingencies. We recognize liabilities for legal and other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other to occur, the low end of the range is accrued.

Derivatives

We enter into derivative contracts on our oil and natural gas products primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. Derivative instruments are reflected on our consolidated balance sheet at their fair value as assets and liabilities. We classify our derivatives as either current or non-current based on their anticipated settlement date. We net derivative assets and liabilities with counterparties where we have a legal right of offset.

All of our derivatives are marked-to-market each period and changes in the fair value of our commodity based derivatives, as well as any realized amounts, are reflected as operating revenues. We classify cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of our oil and natural gas operations, they are classified as cash flows from operating activities. In our consolidated balance sheet,

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receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 6 for a further discussion of our derivatives.

Income Taxes

We record current income taxes based on our estimates of current taxable income and provide for deferred income taxes to reflect estimated future income tax payments and receipts. Changes in tax laws are recorded in the period they are enacted. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We classify all deferred tax assets and liabilities, along with any related valuation allowance, as non-current on the consolidated balance sheet. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. The realization of our deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. We record a valuation allowance against deferred tax assets when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating our valuation allowances, we consider cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowances could materially impact our results of operations.

2. Acquisitions and Divestitures

Acquisitions. In 2018, we completed the acquisition of producing properties and proved undeveloped acreage in Eagle Ford for approximately $246 million, after customary adjustments. Of the total purchase price, we paid $221 million upon closing during the first quarter of 2018 and $25 million to the buyer as a deposit in December 2017. During 2018, we completed an acquisition of additional working interests in certain producing properties in Eagle Ford for approximately $31 million, after customary closing adjustments. Our consolidated balance sheet reflects the cost of each of these assets acquired during the year as proved properties.

Divestitures. During 2018, we also completed the sale of certain assets in Northeastern Utah (NEU), formerly Altamont, for approximately $177 million, after customary adjustments. Of the total sales price, we received a deposit of $18 million (reflected in restricted cash in the balance sheet) in December 2017 and additional cash proceeds of $159 million upon closing. We treated this sale as a normal retirement reflecting the difference between net cash proceeds and the underlying net book value of the assets sold in accumulated depreciation rather than recording a gain on sale of assets. As of December 31, 2017, we classified the assets and liabilities associated with the assets to be sold as held for sale in our consolidated balance sheet.

3. Impairment Charges

We evaluate capitalized costs related to proved properties upon a triggering event (e.g., a significant continued decline in forward commodity prices or significant reduction to development capital) to determine if an impairment of such properties has occurred. Commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in an impairment of the carrying value of our proved and/or unproved properties in the future. Capitalized costs associated with unproved properties (e.g., leasehold acquisition costs associated with non-producing areas) are also assessed upon a triggering event for impairment based on estimated drilling plans and capital expenditures, which may also change relative to forward commodity prices and/or potential lease expirations.

Due to the current oil price environment and the significant reduction to future development capital in the Permian basin, we have recorded non-cash impairment charges during the fourth quarter of 2018 of approximately (i) $1,044 million on our proved properties, reflecting a reduction in the net book value of the proved property in this area to its estimated fair value and (ii) $59 million on our unproved properties.

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4. Income Taxes

Pretax Income (Loss) and Income Tax (Expense) Benefit. The tables below show the pretax loss and the components of income tax benefit for the following periods:

	Year Ended December 31, 2018	2017
	(in millions)	
Pretax Loss	$(1,003)	$(203)
Components of Income Tax Benefit		
Current		
Federal	$—	$9
State	—	—
	—	9
Deferred		
Federal	$—	$—
State	—	—
Total income tax benefit	$—	$9

Effective Tax Rate Reconciliation. Our income taxes included in net income differ from the amount computed by applying the statutory federal income tax rate of 21% for the following reasons:

	Year Ended December 31, 2018	2017
		(in millions)
Income taxes at the statutory federal rate(1)	$211	$ 71
Increase (decrease)		
State income taxes, net of federal income tax effect	8	(1)
Change in enacted tax rate	—	(409)
Change in valuation allowance	(213)	341
Capital loss expiration	(5)	—
Other	(1)	7
Income tax benefit	$—	$ 9

(1) The statutory rates for the years ended December 31, 2018 and 2017 were 21% and 35%, respectively.

The effective tax rate for the year ended December 31, 2018 was 0%. Our effective tax rate differed from the statutory rate of 21% primarily due to the change in our valuation allowance on our net deferred tax assets, non-deductible compensation expenses, and a non-deductible loss carryover. Changes in our deferred taxes from year to year are offset by changes to our related valuation allowance and thus have the effect of eliminating the impact of federal taxes on our income.

The effective tax rate for the year ended December 31, 2017 was 4.5%. Our effective tax rate differed from the statutory rate of 35% primarily due to recording a current income tax benefit and related receivable for the recovery of previously paid alternative minimum taxes based on a change in our tax depreciation elections, the change in our valuation allowance on our net deferred tax assets, and non-deductible compensation expenses.

In December 2017, Congress passed into law the Tax Cuts and Jobs Act (the Act) which lowered the federal corporate tax rate from 35% to 21% effective January 1, 2018. The passage of the Act had no effect on our financial statements since the effect of adjusting the tax rate on all our deferred tax balances was offset by a corresponding adjustment to the valuation allowance on our net deferred assets.

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Deferred Tax Assets and Liabilities. The following are the components of net deferred tax assets and liabilities:

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred tax assets		
Property, plant and equipment	$157	$ 50
Net operating loss carryovers	611	554
Employee benefits	2	2
Financial derivatives	—	8
Legal and other reserves	9	9
Asset retirement obligations	9	8
Interest deduction limitation	76	—
Transaction costs	14	13
Total deferred tax assets	878	644
Valuation allowance	(857)	(644)
Net deferred tax assets	21	—
Deferred tax liabilities		
Financial derivatives	21	—
Total deferred tax liabilities	21	—
Net deferred tax liabilities	$—	$ —

Unrecognized Tax Benefits. As of December 31, 2018, there were no unrecognized tax benefits as income taxes in our financial statements. We did not recognize any interest and penalties related to unrecognized tax benefits (classified as income taxes in our consolidated income statement) in 2018 or 2017, nor do we have any accrued interest and penalties associated with income taxes in our consolidated balance sheet as of December 31, 2018 and December 31, 2017. The Company's and certain subsidiaries' income tax years after 2014 remain open and subject to examination by both federal and state tax authorities, and in 2018 we were notified of an IRS examination of our 2016 U.S. tax return.

Net Operating Loss and Tax Credit Carryovers. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2018 (in millions):

		Expiration Period
U.S. federal net operating loss carryover[(1)]	$ 2,524	2031 - 2037
State net operating loss carryover	$ 447	2026 - 2038

(1) Amounts reflect U.S. federal net operating loss generated prior to 2018. The U.S. federal net operating loss generated in 2018 is $286 million, which does not expire, and is limited to 80% of taxable income per year.

Utilization of $50 million of our federal net operating loss carryovers is subject to the limitations provided under Sections 382 of the Internal Revenue Code. While these limitations restrict the amount of carryovers we could potentially utilize in the next few years, it would not cause any carryovers to expire unused.

Our capital loss carryovers of $23 million expired in 2018. There are no alternative minimum tax credits at December 31, 2018.

Valuation Allowances. As of December 31, 2018 and 2017, we have a valuation allowance on our deferred tax assets of $857 million and $644 million, respectively. These amounts are recorded based on our evaluation of whether it was more likely than not that our deferred tax assets would be realized. Our evaluations considered cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions.

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5. Earnings Per Share

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on net income per common share is antidilutive. Potentially dilutive securities consist of our stock options, restricted stock, performance share unit awards and performance unit awards. For the years ended December 31, 2018 and 2017, we incurred net losses and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

6. Fair Value Measurements

We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each of the levels are described below:

- Level 1 instruments' fair values are based on quoted prices in actively traded markets.
- Level 2 instruments' fair values are based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets).
- Level 3 instruments' fair values are partially calculated using pricing data that is similar to Level 2 instruments, but also reflect adjustments for being in less liquid markets or having longer contractual terms.

The following table presents the carrying amounts and estimated fair values of our financial instruments:

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Short-term debt	$58	$ 44	$21	$ 19
Long-term debt	$4,380	$ 2,532	$4,072	$ 3,248
Derivative instruments	$114	$ 114	$5	$ 5

For the years ended December 31, 2018 and 2017, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. Our long-term debt obligations (see Note 8) have various terms, and we estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, considering our credit risk.

Oil, Natural Gas and NGLs Derivative Instruments. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil, natural gas and NGLs through the use of financial derivatives. As of December 31, 2018, we had derivatives contracts in the form of collars and three-way collars on 16 MMBbls of oil (14 MMBbls in 2019 and 2 MMBbls in 2020). In addition to our oil derivatives, we had derivative contracts in the form of fixed price swaps and collars on 26 TBtu of natural gas in 2019. As of December 31, 2017, we had derivative contracts for 14 MMBbls of oil, 33 TBtu of natural gas and 92 MMGal of ethane and propane. In addition to the contracts above, we have derivative contracts related to locational basis differences on our oil and natural gas production. None of our derivative contracts are designated as accounting hedges.

As of December 31, 2018 and 2017, all derivative financial instruments were classified as Level 2. Our assessment of the level of an instrument can change over time based on the maturity or liquidity of the instrument, which can result in a change in the classification level of the financial instrument.

The following table presents the fair value associated with our derivative financial instruments as of December 31, 2018 and 2017. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our consolidated balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

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	Level 2							
	Derivative Assets				Derivative Liabilities			
	Gross		Balance Sheet Location		Gross		Balance Sheet Location	
	Fair Value	Impact of Netting	Current	Non-current	Fair Value	Impact of Netting	Current	Non-current
		(in millions)				(in millions)		
December 31, 2018								
Derivative instruments	$116	$(2)	$ 101	$ 13	$(2)	$2	$ —	$ —
December 31, 2017								
Derivative instruments	$33	$(11)	$ 18	$ 4	$(28)	$11	$ (17)	$ —

For the years ended December 31, 2018 and 2017, we recorded a derivative gain of $84 million and $41 million respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statements.

Credit Risk. We are subject to a risk of loss on our derivative instruments that could occur if our counterparties do not perform pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require that we (i) evaluate potential counterparties' financial condition to determine their credit worthiness; (ii) monitor our oil, natural gas and NGLs counterparties' credit exposures; (iii) review significant counterparties' credit from physical and financial transactions on an ongoing basis; (iv) use contractual language that affords us netting or set-off opportunities to mitigate risk; and (v) when appropriate, require counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets related to derivatives as of December 31, 2018 represent financial instruments from five counterparties, all of which are lenders associated with our Reserve-based Loan facility (RBL Facility) with an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating. Subject to the terms of our RBL Facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL Facility.
Other Fair Value Considerations. During the year ended December 31, 2018, we recorded non-cash impairment charges on our proved and unproved properties in the Permian basin. The estimate of fair value of our proved oil and natural gas properties used to determine the impairment was estimated using a discounted cash flow model and other relevant financial and transactional market participant data. These estimates represented a Level 3 fair value measurement. See Notes 1 and 3 for a further discussion of our impairment charges.

7. Property, Plant and Equipment

Oil and Natural Gas Properties. As of December 31, 2018 and 2017, we had approximately $3.8 billion and $4.4 billion, respectively, of total property, plant, and equipment, net of accumulated depreciation, depletion, and amortization on our balance sheet, substantially all of which relates to proved and unproved oil and natural gas properties. During the fourth quarter of 2018, we recorded non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin. See Note 3 for details of the impairment charge.
Our capitalized costs related to proved and unproved oil and natural gas properties by area for the periods ended December 31 were as follows:

	2018	2017
	(in millions)	
Proved		
Eagle Ford	$3,898	$3,219
Northeastern Utah	1,659	1,542

Permian	1,787	2,705
Total Proved	7,344	7,466
Unproved		
Permian	—	66
Less accumulated depletion	(3,607)	(3,137)
Net capitalized costs for oil and natural gas properties	$3,737	$4,395

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During 2018 and 2017, we recorded less than $1 million and $5 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. During 2018, we transferred approximately $7 million from unproved properties to proved properties. Suspended well costs were not material as of December 31, 2018 or December 31, 2017.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We settle these obligations when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue these obligations when we can estimate the timing and amount of their settlement.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7 percent and 9 percent on a significant portion of our obligations and a projected inflation rate of 2.5 percent. Changes in estimates in the table below represent changes to the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of our obligations to plug and abandon oil and natural gas wells and the costs to do so, or reassessing our assumptions in light of changing market conditions. The net asset retirement liability as of December 31 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability for the periods ended December 31 were as follows:

	2018	2017
	(in millions)	
Net asset retirement liability at January 1	$ 35	$ 41
Liabilities incurred	1	—
Liabilities settled	—	(2)
Accretion expense	3	3
Changes in estimate	3	(5)
Liability reclassified as held for sale	—	(2)
Net asset retirement liability at December 31	$ 42	$ 35

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. We capitalize interest primarily on the costs associated with drilling and completing wells until production begins using a weighted average interest rate on our outstanding borrowings. Capitalized interest for the years ended December 31, 2018 and 2017 was approximately $5 million and $4 million, respectively.

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8. Long-Term Debt

Listed below are our debt obligations as of the periods presented:

	Interest Rate	December 31, 2018	December 31, 2017
		(in millions)	
RBL credit facility - due November 23, 2021[(1)]	Variable	$100	$ 595
Senior secured term loans:			
Due May 24, 2018[(2)(3)]	Variable	—	21
Due April 30, 2019[(4)]	Variable	8	8
Senior secured notes:			
Due May 1, 2024	9.375 %	1,092	—
Due November 29, 2024	8.00 %	500	500
Due February 15, 2025	8.00 %	1,000	1,000
Due May 15, 2026	7.75 %	1,000	—
Senior unsecured notes:			
Due May 1, 2020	9.375 %	232	1,200
Due September 1, 2022	7.75 %	182	250
Due June 15, 2023	6.375 %	324	519
Total debt		4,438	4,093
Less short-term debt, net of debt issue costs of less than $1 million		(58)	(21)
Total long-term debt		4,380	4,072
Less debt discount and non-current portion of unamortized debt issue costs[(5)]		(95)	(50)
Total long-term debt, net		$4,285	$ 4,022

(1) Carries interest at a specified margin over LIBOR of 2.50% to 3.50%, based on borrowing utilization.

(2) Issued at 99% of par and carries interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of December 31, 2017, the effective interest rate of the term loan was 4.23%.

(3) In April 2018, we retired the term loan in full.

(4) Carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of December 31, 2018 and 2017, the effective interest rate for the term loan was 6.21% and 4.98%, respectively.

(5) Includes debt discount of $42 million and less than $1 million as of December 31, 2018 and 2017, respectively, associated with our senior secured notes maturing in 2024 and unamortized debt issue costs of $53 million and $50 million as of December 31, 2018 and 2017, respectively.

In May 2018, we issued $1 billion of 7.75% senior secured notes which mature in 2026 and used the proceeds (less fees and expenses) to repay $907 million of the amounts outstanding at that time under our RBL Facility. In conjunction with issuing the notes, we also reduced the amount of RBL Facility commitments to $629 million, which resulted in recording a loss of $2 million reflecting the elimination of associated unamortized debt-issue costs.

In January 2018, we completed an exchange of approximately $1,147 million of our senior unsecured notes maturing in May 2020, September 2022 and June 2023 for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million. The exchange transaction was accounted for as a modification of debt for our senior unsecured notes maturing in May 2020 and an extinguishment of debt for our senior unsecured notes maturing in September 2022 and June 2023. In conjunction with the exchange, we incurred approximately $62 million in related fees, recording $48 million as debt discount associated with exchanging our 2020 notes and $12 million in loss on modification of debt. In addition, we recorded a net gain on extinguishment of debt in the amount of $53 million primarily associated with retiring a portion of our 2022 and 2023 notes at less than face value.

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In 2018 and 2017, we also repurchased additional debt as follows:

	Year ended December 31, 2018	2017
	(in millions)	
Debt repurchased - face value[(1)]	84	157
Cash paid	49	118
Gain on extinguishment of debt[(2)]	34	37

(1) In 2018 and 2017, repurchases were associated with 2022 and 2023 senior unsecured notes and 2020 and 2023 senior unsecured notes, respectively.

(2) Includes $1 million and $2 million for the years ended December 31, 2018 and 2017, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs.

In 2019, we paid approximately $40 million in cash to repurchase a total of $50 million in aggregate principal amount of our senior unsecured notes.

In 2017, we issued $1 billion of 8.00% senior secured notes which mature in 2025 and used the proceeds to repay certain senior secured term loans and notes and repay a portion of the amounts outstanding under our RBL Facility. In conjunction with these transactions, we recorded a loss on extinguishment of debt of approximately $53 million (including $30 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts).

Reserve-based Loan Facility. We have a RBL Facility in place which allows us to borrow funds or issue letters of credit (LCs) up to $629 million. The RBL Facility matures in November 2021. As of December 31, 2018, we had $510 million of capacity remaining with approximately $19 million of LCs issued and $100 million outstanding under the RBL Facility. Listed below is a further description of our credit facility as of December 31, 2018:

Credit Facility	Maturity Date	Interest Rate	Commitment fees
$1.36 billion RBL	November 23, 2021	LIBOR + 2.5%[(1)] 2.5% for LCs	0.375% commitment fee on unused capacity

(1) Based on our December 31, 2018 borrowing level. Amounts outstanding under the RBL Facility bear interest at specified margins over the LIBOR of between 2.50% and 3.50% for Eurodollar loans or at specified margins over the Alternative Base Rate (ABR) of between 1.50% and 2.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In November 2018, our RBL Facility borrowing base was affirmed at $1.36 billion and total commitments remained at $629 million. Downward revisions of our oil and natural gas reserve volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, or sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant.

Restrictive Provisions/Covenants. The availability of borrowings under our RBL Facility and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions, including first lien debt to EBITDAX and current ratio financial covenants. First lien debt for purposes of the covenant only includes amounts borrowed under our RBL Facility. As part of our RBL Facility amendment in May 2018, we (i) extended our first lien debt to EBITDAX financial covenant and reduced the ratio to 2.25 to 1.00 and (ii) included a financial covenant for a current ratio (as defined in the RBL Facility) to be not less than 1.00 to 1.00. As of December 31, 2018, we were in compliance with our debt covenants.

Under our various debt agreements, we are limited in our ability to repurchase certain tranches of non-RBL Facility debt. Certain other covenants and restrictions, among other things, also limit or place certain conditions on our ability to incur or guarantee additional indebtedness, make restricted payments, pay dividends on equity interests, redeem, repurchase or retire equity interests or subordinated indebtedness, sell assets, make investments, create certain liens, prepay debt obligations, engage in certain transactions with affiliates, and enter into certain hedging agreements.

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9. Commitments and Contingencies

Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each matter, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of our current matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2018, we had approximately $5 million accrued for all outstanding legal matters.

FairfieldNodal v. EP Energy E&P Company, L.P. On March 3, 2014, Fairfield filed suit against one of our subsidiaries in the 157th District Court of Harris County, Texas, claiming we were contractually obligated to pay a transfer fee of approximately $21 million for seismic licensing, triggered by a change in control with the Sponsors' acquisition of our predecessor entity in 2012. Prior to the change in control, we had unilaterally terminated the seismic licensing agreements, and we returned the applicable seismic data. Fairfield also claimed EP Energy did not properly maintain the confidentiality of the seismic data and interpretations made from it. In April 2015, the district court granted summary judgment to EP Energy, and Fairfield then appealed. On July 6, 2017, an intermediate court of appeals in Texas reversed the judgment related to the transfer fee and denied rehearing on October 5, 2017. We filed a petition for review in the Texas Supreme Court in December 2017 and filed briefing on the merits in December 2018. At this time, we are unable to estimate the amount or range of possible loss, if any, on this matter.

Weyerhaeuser Company v. Pardee Minerals LLC, et al. On July 5, 2017, Weyerhaeuser filed suit against one of our subsidiaries, among other defendants, in the United States District Court for the Western District of Louisiana. Weyerhaeuser seeks to recoup the value of production after November 2006 (approximately $15.6 million) plus judicial interest (approximately $7.8 million at this time) from certain wells drilled by EP Energy between 2002 and 2013 on leases Weyerhaeuser claims were invalid. Weyerhaeuser alleges that lessees prior to EP Energy had not drilled wells in good faith to perpetuate the associated mineral servitude (rights conveyed to produce minerals), rendering EP Energy's subsequent lease invalid. A trial date has been set for December 9, 2019. At this time, we are unable to estimate the amount or range of possible loss, if any, on this matter.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestiture of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets previously purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we could be required to assume all, or a portion of the plugging or abandonment obligations on assets we no longer own or operate. As of December 31, 2018, we had approximately $3 million accrued related to these indemnifications and other matters.

Non-Income Tax Matters. We are under a number of examinations by taxing authorities related to non-income tax matters. As of December 31, 2018, we had approximately $42 million accrued (in other accrued liabilities in our consolidated balance sheet) in connection with ongoing examinations related to certain prior period non-income tax matters.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the Environmental Protection Agency (EPA), issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. Our management believes that we are in substantial compliance with applicable environmental laws and regulations, and we have not experienced any material adverse effect from compliance with these environmental requirements. For additional details on certain environmental matters, including matters related to climate change, air quality and other emissions, hydraulic fracturing regulations and waste handling, refer to Part I, Item 1A, "Risk Factors".

While our reserves for environmental matters are currently not material, there are still uncertainties related to the ultimate costs we may incur in the future in order to comply with increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations. Based upon our evaluation and experience to date, however, we believe

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our accruals for these matters are adequate. It is possible that new information or future developments could result in substantial additional costs and liabilities which could require us to reassess our potential exposure related to these matters and to adjust our accruals accordingly, and these adjustments could be material.

Lease Obligations

Our noncancellable leases classified as capital leases for accounting purposes include certain compressors under long-term arrangements and are capitalized upon commencement of the lease term at the lower of the fair value of the leased asset or the present value of the minimum lease payments. Capitalized leased assets are included in other property, plant and equipment in our consolidated balance sheet and amortized over the lease term in depreciation, depletion and amortization in our consolidated statements of income. Capital lease obligations are included in other non-current liabilities in our consolidated balance sheet. As of December 31, 2018, the total carrying value of assets under capital lease was $13 million, net of accumulated depreciation of $1 million. We did not acquire any property and/or equipment under capital leases as of December 31, 2017.

Our noncancellable leases classified as operating leases for accounting purposes include those for office space and various equipment. All related payments for operating leases are recognized as expense on a straight-line basis over the lease term.

Future minimum annual rental commitments under non-cancelable future operating and capital lease commitments at December 31, 2018, were as follows:

Year Ending December 31,	Operating Leases	Capital Leases
	(in millions)	
2019	$ 4	$ 5
2020	4	5
2021	4	4
2022	4	4
Thereafter	12	2
Total	$ 28	$ 20
Less: imputed interest		(8)
Present value of capital lease obligations		$ 12

Rental expense for the years ended December 31, 2018 and 2017 was $7 million and $6 million, respectively.

Other Commercial Commitments

At December 31, 2018, we have various commercial commitments totaling $260 million primarily related to commitments and contracts associated with volume and transportation, completion activities and seismic activities. Our annual obligations under these arrangements are $101 million in 2019, $59 million in 2020, $53 million in 2021, $40 million in 2022, and $7 million thereafter.

10. Long-Term Incentive Compensation / 401(k) Retirement Plan

Overview. Under our current stock-based compensation plans (the EP Energy Corporation 2014 Omnibus Incentive Plan and 2017 EP Energy Corporation Employment Inducement Plan), we may issue to our employees and non-employee directors various forms of long-term incentive (LTI) compensation including stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares/units, incentive awards, cash awards, and other stock-based awards. We are authorized to grant awards of up to 36,832,525 shares of our common stock for awards under these plans, with 8,645,338 shares remaining available for issuance as of December 31, 2018.

In addition, in conjunction with the acquisition of certain of our subsidiaries by Apollo and other private equity investors in 2012 (the Acquisition), we issued Class B shares (formerly management incentive units intended to constitute profits interests) which become payable only on the achievement of certain predetermined performance measures as further described below. No additional Class B shares are available for issuance.

We record stock-based compensation expense as general and administrative expense over the requisite service period. For the years ended December 31, 2018 and 2017, we recognized pre-tax compensation expense related to our LTI programs, net of the impact of forfeitures of approximately $14 million and $(19) million, respectively, and recorded an associated income tax benefit of $4 million and $5 million for the years 2018 and 2017, respectively. Included in compensation expense in 2017

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is a reduction of approximately $33 million reflecting the forfeitures of LTI awards and the reversal of previously recognized compensation expense resulting from the change in our management and staff reductions in 2017.

Restricted stock. We grant shares of restricted common stock which carry voting and dividend rights and may not be sold or transferred until they are vested. The fair value of our restricted stock is determined on the date of grant and these shares generally vest in equal amounts over 3 years from the date of the grant. A summary of the changes in our non-vested restricted shares for the year ended December 31, 2018 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	5,283,986	$ 4.93
Granted	7,016,525	$ 1.94
Vested	(3,587,606)	$ 3.92
Forfeited	(1,652,571)	$ 4.00
Non-vested at December 31, 2018	7,060,334	$ 2.69

The total unrecognized compensation cost related to these arrangements at December 31, 2018 was approximately $13 million, which is expected to be recognized over a weighted average period of 2 years.

Performance Share Units. In 2018 and 2017, we granted 618,720 and 912,000 performance share units (PSUs) to members of EP Energy's management team and certain EP Energy employees, of which 1,508,760 were outstanding at December 31, 2018. The PSUs represent a contractual right to receive one share of EP Energy’s common stock if certain conditions are met, and the number of PSUs actually earned, if any, will be based upon achievement of specified stock price goals over a four-year performance period (grant date thru October 2021). For accounting purposes, the PSUs are treated as an equity award and will vest over a weighted average period of three years with expense recognized on an accelerated basis over the life of the award. Of the 1,508,760 PSU’s outstanding at December 31, 2018, 1,224,000 shares will remain subject to certain settlement and transfer restrictions from November 2021 through October 2024 unless certain conditions are satisfied.

The grant date fair value of the 2018 and 2017 awards was approximately $5 million and $12 million, respectively, as determined by a Monte Carlo simulation, utilizing multiple input variables that determine the probability of satisfying the market condition stipulated in the award. Volatility was based on life-to-date volatility of EP Energy’s common stock, which has been publicly traded for an amount of time less than the contractual term of the award. We estimated the risk free rate based on zero coupon U.S. Treasury STRIPS (Separate Trading of Registered Interest and Principal of Securities) that have a term equal to the length of the period from the valuation date to the final vest date. The following table summarizes the significant assumptions used to calculate the grant date fair value of the PSUs:

	2018 Awards	2017 Awards
Expected Term in Years	4	6
Expected Volatility	89.62 %	100.03 %
Risk-Free Interest Rate	2.75 %	1.89 %

Total compensation cost related to our non-vested performance share units not yet recognized at December 31, 2018 was $9 million, which is expected to be recognized over a weighted average period of 3 years.

Other. We have issued and/or granted, in prior periods, (i) Class B shares (including those issued to EPE Employee Holdings, II, LLC, a subsidiary), which payout only occurs on the achievement of certain predetermined performance measures (e.g., certain liquidity events in which our private equity investors receive a return of at least one times their invested capital plus a stated return), (ii) stock options at a strike price of $19.82 per share and (iii) total shareholder return (TSR) based performance units treated as liability awards. Due to both reductions in force affecting the holders of these awards and/or declines in stock price performance in recent years, these awards will not materially impact the company and as of December 31, 2018, we had (i) unrecognized compensation expense of $1 million related to Class

B shares, which will only be recognized should the liquidity events described above occur and the right to such amounts become nonforfeitable and (ii) less than $1 million in unrecognized compensation cost for non-vested stock options and performance units, which is expected to be recognized over a weighted average period of 1 year.

401(k) Retirement Plan. We sponsor a tax-qualified defined contribution retirement plan for a broad-based group of employees. We make matching contributions (dollar for dollar up to 6% of eligible compensation) and non-elective employer contributions (5% of eligible compensation) to the plan, and individual employees are also eligible to contribute to the defined

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contribution plan. During 2018 and 2017, we contributed $6 million and $7 million, respectively, of matching and non-elective employer contributions.

11. Related Party Transactions

Joint Venture. In 2017, we entered into a drilling joint venture with Wolfcamp Drillco Operating L.P. (the Investor), which is managed and controlled by an affiliate of Apollo Global Management LLC, to fund future oil and natural gas development in the Permian basin. Subsequently, Access Industries acquired an indirect minority ownership interest in the Investor and therefore is also indirectly responsible for funding a portion of the Investor's capital commitment. The Investor agreed to fund 60 percent of the estimated drilling, completion and equipping costs in the joint venture wells, divided into two approximately $225 million investment tranches, in exchange for a 50 percent working interest. We are the operator of the joint venture assets. Once the Investor achieves a 12 percent internal rate of return on its invested capital in each tranche, its working interest reverts to 15 percent. We have completed the planned activity in the first tranche. In April 2018, we amended the drilling joint venture to direct the second tranche investment to the Eagle Ford. The first wells in the second tranche began producing in the third quarter of 2018. At December 31, 2018 and 2017, we had accounts receivable of $47 million and $5 million, respectively, from our Investor and accounts payable of $20 million and $10 million, respectively, to our Investor reflected in our consolidated balance sheet.

Affiliate Payments. In 2017, in connection with the release of members of the leadership team of a portfolio company of funds managed by Apollo Management, LLC (Apollo) affiliates to join the Company, the Company reimbursed that portfolio company approximately $4 million for money contributed to it by fund investors (other than Apollo).

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Supplemental Oil and Natural Gas Operations (Unaudited)
We are engaged in the exploration for, and the acquisition, development and production of oil, natural gas and NGLs, in the United States (U.S.).
Capitalized Costs. Capitalized costs relating to domestic oil and natural gas producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	2018	2017[(1)]
Oil and natural gas properties	$7,344	$7,532
Less accumulated depreciation, depletion and amortization	3,607	3,137
Net capitalized costs[(2)]	$3,737	$4,395

(1) December 31, 2017 does not include amounts related to certain assets in NEU as these capitalized costs are reflected as assets held for sale on our consolidated balance sheet.
(2) During the year ended December 31, 2018, we recorded non-cash impairment charges of approximately $1,044 million and $59 million on our proved and unproved properties, respectively, in the Permian basin.

Total Costs Incurred. Costs incurred in oil and natural gas producing activities, whether capitalized or expensed, were as follows for the years ended December 31, 2018 and 2017 (in millions):

	U.S.
2018:	
Property acquisition costs	
Proved properties[(1)]	$322
Unproved properties	—
Exploration costs (capitalized and expensed)	7
Development costs	649
Costs expended	978
Asset retirement obligation costs	1
Total costs incurred	$979
2017 Consolidated:	
Property acquisition costs	
Proved properties	$7
Unproved properties[(1)]	27
Exploration costs (capitalized and expensed)	6
Development costs	544
Costs expended	584
Asset retirement obligation costs	—
Total costs incurred	$584

(1) Includes approximately $5 million for both of the years ended December 31, 2018 and 2017 related to lease extensions and renewals.

We capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. The table above includes capitalized labor costs of $14 million and $23 million for the years ended December 31, 2018 and 2017, respectively, and capitalized interest of $5 million and $4 million for the same periods.
Oil and Natural Gas Reserves. We employed Ryder Scott Company, L.P. (Ryder Scott) to evaluate and prepare the estimates of our net proved reserves as of December 31, 2018. Ryder Scott prepared 100% (by volume) of our total net proved developed and undeveloped (PUD) reserves on a barrel of oil equivalent basis. The overall procedures and methodologies utilized by Ryder Scott in evaluating and preparing estimates of our net proved reserves as of December 31, 2018 complied with current SEC regulations. Ryder Scott’s report is included as an exhibit to this

Annual Report on Form 10-K.
Net quantities of proved developed and undeveloped reserves of natural gas, oil and NGLs and changes in these reserves at December 31, 2018 presented in the tables below are based on Ryder Scott's report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate. Our 2018 proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2018 except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

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	Year Ended December 31, 2018[1]			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	652	203,865	79,477	392.1
Revisions due to prices	31	7,975	3,932	17.1
Revisions other than prices[2]	(75)	(31,581)	(23,268)	(67.4)
Purchase of reserves	31	14,902	5,285	25.4
Sales of reserves in place	(20)	(9,785)	(152)	(13.3)
Production	(45)	(16,719)	(5,220)	(29.4)
End of year	574	168,657	60,054	324.5
Proved developed reserves:				
Beginning of year	372	114,282	41,989	218.3
End of year	434	111,201	49,942	233.6
Proved undeveloped reserves:				
Beginning of year	280	89,584	37,489	173.8
End of year	140	57,455	10,111	90.9

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $65.56 per Bbl (WTI), $3.10 per MMBtu (Henry Hub) and $23.60 per Bbl of NGLs.

(2) The 67 MMBoe of revisions other than prices primarily includes negative revisions of 74 MMBoe due to a reallocation of capital from the Permian to other development areas and a positive revision of 12 MMBoe associated with increased drilling activity in the Eagle Ford and NEU.

	Year Ended December 31, 2017[1]			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	732	219,783	90,575	432.4
Revisions due to prices	16	5,937	1,733	10.4
Revisions other than prices[2]	(72)	(3,369)	(11,950)	(27.3)
Extensions and discoveries[3]	44	10,143	6,752	24.2
Purchase of reserves	—	102	16	0.1
Sales of reserves in place	(22)	(11,898)	(2,183)	(17.7)
Production	(46)	(16,833)	(5,466)	(30.0)
End of year	652	203,865	79,477	392.1
Proved developed reserves:				
Beginning of year	346	108,133	38,887	204.6
End of year	372	114,282	41,989	218.3
Proved undeveloped reserves:				
Beginning of year	386	111,649	51,689	227.8
End of year	280	89,584	37,489	173.8

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $51.34 per Bbl (WTI) and $2.98 per MMBtu (Henry Hub).

(2) The 27 MMBoe of revisions other than prices includes 23 MMBoe of negative PUD revisions due to a reallocation of capital in our development areas and 4 MMBoe of negative revisions. The negative 4 MMBoe of revisions includes a negative revision of 13 MMBoe in the Permian, a net positive revision of 6 MMBoe in Eagle Ford and a net positive revision of 3 MMBoe in NEU.

(3) The 24 MMBoe of extensions and discoveries are all in the Permian. Of the 24 MMBoe of extensions and discoveries, 16 MMBoe were liquids representing 70% of EP Energy's total extensions and discoveries.

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In accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month preceding the 12-month period prior to the end of the reporting period. The first day 12-month average price used to estimate our proved reserves at December 31, 2018 was $65.56 per barrel of oil (WTI), $3.10 per MMBtu for natural gas (Henry Hub) and $23.60 per Bbl of NGLs.

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of "reasonable certainty" be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices, economic conditions and government restrictions. In addition, as a result of drilling, testing and production subsequent to the date of an estimate; a revision of that estimate may be necessary. Reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Estimating quantities of proved oil and natural gas reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon economic factors, such as oil and natural gas prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Subsequent to December 31, 2018, there have been no major discoveries, favorable or otherwise, on our proved reserves volumes that may be considered to have caused a significant change in our estimated proved reserves at December 31, 2018.

Results of Operations. Results of operations for oil and natural gas producing activities for the years ended December 31, 2018 and 2017 (in millions):

	U.S.
2018:	
Net Revenues[(1)] — Sales to external customers	$1,240
Costs of products and services	(111)
Production costs[(2)]	(231)
Impairment charges	(1,103)
Depreciation, depletion and amortization[(3)]	(496)
Exploration and other expense	(5)
	(706)
Income tax benefit	148
Results of operations from producing activities	$(558)
2017:	
Net Revenues[(1)] — Sales to external customers	$1,025
Costs of products and services	(131)
Production costs[(2)]	(223)
Depreciation, depletion and amortization[(3)]	(476)
Exploration and other expense	(12)

	183
Income tax expense	(66)
Results of operations from producing activities	$117

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(1) Excludes the effects of oil and natural gas derivative contracts.
(2) Production costs include lease operating expense and production related taxes, including ad valorem and severance taxes.
(3) Includes accretion expense on asset retirement obligations of $3 million for each of the years ended December 31, 2018 and 2017.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to our consolidated proved oil and natural gas reserves at December 31 is as follows (in millions):

	U.S.
2018:	
Future cash inflows[1]	$13,278
Future production costs	(4,708)
Future development costs	(1,703)
Future income tax expenses	(456)
Future net cash flows	6,411
10% annual discount for estimated timing of cash flows	(3,061)
Standardized measure of discounted future net cash flows	$3,350
2017:	
Future cash inflows[1]	$12,395
Future production costs	(5,363)
Future development costs	(2,692)
Future income tax expenses	(149)
Future net cash flows	4,191
10% annual discount for estimated timing of cash flows	(2,158)
Standardized measure of discounted future net cash flows	$2,033

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2018 and 2017. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in our consolidated standardized measure of discounted future net cash flows (in millions):

	Year Ended December 31,[1]	
	2018	2017
Consolidated:		
Sales and transfers of oil and natural gas produced net of production costs	$ (1,005)	$ (801)
Net changes in prices and production costs	1,620	1,048
Extensions, discoveries and improved recovery, less related costs	—	98
Changes in estimated future development costs	360	(196)
Previously estimated development costs incurred during the period	381	441
Revision of previous quantity estimates	(677)	(181)
Accretion of discount	228	157
Net change in income taxes	(80)	(1)
Purchase of reserves in place	355	1
Sales of reserves in place	(165)	(48)
Change in production rates, timing and other	300	488
Net change	$ 1,317	$ 1,006
Representative NYMEX prices:[2]		
Oil (Bbl)	$ 65.56	$ 51.34
Natural gas (MMBtu)	$ 3.10	$ 2.98

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.
Average first day of the month spot price for the preceding 12-month period before price differentials and deducts.
(2) Price differentials and deducts were applied when the estimated future cash flows from estimated production from proved reserves were calculated.

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

As of December 31, 2018, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are 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, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2018. See Part II, Item 8, “Financial Statements and Supplementary Data” under Management’s Annual Report on Internal Control Over Financial Reporting.

Design and Evaluation of Internal Control Over Financial Reporting.

Our management has included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report for the fiscal year ended December 31, 2018. The Company’s independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report on the effectiveness of the Company’s internal control over financial reporting. These reports are included in “Item 8. Financial Statements and Supplementary Data” under the captions entitled “Management’s Annual Report on Internal Control Over Financial Reporting” and “Report of Independent Registered Public Accounting Firm” (referencing the “Opinion on Internal Control over Financial Reporting”), respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2018 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

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PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES
(a) The following documents are filed as a part of this report:
1. Financial statements: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.
2. Financial statement schedules: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

3. and (b). Exhibits
The exhibits identified below are filed as part of this report and are hereby incorporated herein by reference. The list below is a list of those exhibits filed herewith, and includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Annual Report on Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.
The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:
•should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
•may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
•may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
•were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.
Exhibits filed with this report are designated by “*”. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a “+” constitute a management contract or compensatory plan or arrangement. Exhibits designated with a “†” indicate that a confidential treatment has been granted with respect to certain portions of the exhibit. Omitted portions have been filed separately with the SEC. Exhibits designated with a "#" have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A list of these exhibits and schedules is included after the table of contents in the Participation and Development Agreement. The Company agrees to furnish a supplemental copy of any such omitted exhibit or schedule to the SEC upon request.

Exhibit No.	Exhibit Description
2.1	Letter Agreement, dated as of January 24, 2017, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P. (Exhibit 2.6 to Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
#2.2	Amended and Restated Participation and Development Agreement, dated as of April 27, 2018, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P. (Exhibit 2.1 to Company's Current Report on Form 8-K filed with the SEC on May 3, 2018).
#2.3	First Amendment to Amended and Restated Participation and Development Agreement, dated as of September 26, 2018, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P. (Exhibit 2.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2018, filed with the SEC on November 8, 2018).
#2.4*	Second Amendment to Amended and Restated Participation and Development Agreement, dated as of December 19, 2018, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P.
3.1	Second Amended and Restated Certificate of Incorporation of EP Energy Corporation (Exhibit 3.1 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
3.2	Amended and Restated Bylaws of EP Energy Corporation (Exhibit 3.2 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
4.1	Indenture, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC) and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.2	Indenture, dated as of August 13, 2012, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.3	Indenture, dated as of May 28, 2015, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).
4.4	Indenture, dated as of November 29, 2016, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral

	agent (Exhibit 4.1 to Company's Current Report on Form 8-K, filed with the SEC on November 30, 2016).
4.5	Indenture, dated as of February 6, 2017, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
4.6	Second Supplemental Indenture, dated as of December 21, 2017, by and among EP Energy LLC, Everest Acquisition Finance Inc., and Wilmington Trust, National Association, as trustee (Exhibit 4.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on December 22, 2017).
4.7	Indenture, dated as of January 3, 2018, by and among EP Energy LLC, Everest Acquisition Finance Inc. the Subsidiary Guarantors thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the SEC on January 4, 2018).
4.8	Registration Rights Agreement, dated as of May 28, 2015, between EP Energy LLC, Everest Acquisition Finance Inc. and RBC Capital Markets, LLC, as representative of the several initial purchasers, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).
4.9	Registration Rights Agreement, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC), Everest Acquisition Finance Inc. and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as representatives of the several initial purchasers, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.10	Registration Rights Agreement, dated as of August 13, 2012, between EP Energy LLC, Everest Acquisition Finance Inc. and Citigroup Global Markets Inc., as representative of the several initial purchasers, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.11	Registration Rights Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 4.8 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).

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Exhibit No.	Exhibit Description
4.12	Indenture, dated as of May 23, 2018, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Subsidiary Guarantors thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.1	Credit Agreement, dated as of May 24, 2012, by and among EPE Holdings, LLC, as Holdings, EP Energy LLC (f/k/a Everest Acquisition LLC), as the Borrower, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent, and the other parties party thereto (Exhibit 10.1 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.2	Guarantee Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, the Domestic Subsidiaries of the Borrower signatory thereto and JPMorgan Chase Bank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.3	Collateral Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.4	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.4 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.5	Pledge Agreement, dated as of May 24, 2012, by and among El Paso Brazil, L.L.C., as Pledgor, and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.6	Amendment, dated as of August 17, 2012, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.15 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.7	Second Amendment, dated as of March 27, 2013, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on May 9, 2013).
10.8	Third Amendment, dated as of October 27, 2014, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank,

	N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on April 30, 2015).
10.9	Fourth Amendment, dated as of April 6, 2015, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on April 7, 2015).
10.10	Fifth Amendment, dated as of May 2, 2016, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on May 4, 2016).
10.11	Sixth Amendment, dated as of November 9, 2016, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, filed with the SEC on August 3, 2017).
10.12	Seventh Amendment, dated as of April 24, 2017, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.2 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, filed with the SEC on August 3, 2017).
10.13*	Eighth Amendment to Credit Agreement and Amendment to Collateral Agreement, dated as of May 23, 2018, to the Credit Agreement, dated as of May 24, 2012 (as amended, amended and restated, modified or supplemented from time to time), among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent.
10.14	Consent and Agreement to Credit Agreement, dated as of June 7, 2013, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.3 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013, filed with the SEC on August 14, 2013).

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Exhibit No.	Exhibit Description
10.15	Assumption and Ratification Agreement, dated as of April 30, 2014, entered into by EPE Acquisition, LLC, in favor of the Secured Parties (as defined in the Credit Agreement) (Exhibit 10.9 to Company's Annual Report on Form 10-K, filed with the SEC on February 23, 2015).
10.16	Senior Lien Intercreditor Agreement, dated as of May 24, 2012, among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent, Senior Secured Notes Collateral Agent and Applicable Second Lien Agent, Wilmington Trust, National Association, as Trustee under the Senior Secured Notes Indenture, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.17	Term Loan Agreement, dated as of April 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), as Borrower, the Lenders party thereto, Citibank, N.A., as Administrative Agent and Collateral Agent, and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as Co-Lead Arrangers (Exhibit 10.7 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.18	Guarantee Agreement, dated as of April 24, 2012, by and between Everest Acquisition Finance Inc., as Guarantor, and Citibank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.8 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.19	Collateral Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.9 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.20	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.10 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.21	Amendment No. 1, dated as of August 21, 2012, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.16 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.22	Joinder Agreement, dated as of August 21, 2012, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.17 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.23	

	Incremental Facility Agreement, dated October 31, 2012, to the Term Loan Agreement, dated as of April 24, 2012 and amended by that certain Amendment No. 1 dated as of August 21, 2012, among EP Energy LLC, the lenders from time to time party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on November 5, 2012).
10.24	Reaffirmation Agreement, dated as of October 31, 2012, among EP Energy LLC, each Subsidiary Party party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on November 5, 2012).
10.25	Amendment No. 2, dated as of May 2, 2013, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.26	Joinder Agreement, dated as of May 2, 2013, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.27	Pari Passu Intercreditor Agreement, dated as of May 24, 2012, among Citibank, N.A., as Second Lien Agent, Citibank, N.A., as Authorized Representative for the Term Loan Agreement, Wilmington Trust, National Association, as the Initial Other Authorized Representative and each additional Authorized Representative from time to time party hereto (Exhibit 10.12 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.28	Consent and Exchange Agreement, dated as of August 24, 2016, among EP Energy LLC, the other credit parties party thereto, the lenders party thereto, the additional lender party thereto, and Citibank, N.A. (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.29	Guarantee Agreement, dated as of August 24, 2016, among each Subsidiary of EP Energy LLC listed therein and Citibank, N.A., as collateral agent (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.30	Collateral Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).

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Exhibit No.	Exhibit Description
10.31	Pledge Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.32	Amended and Restated Senior Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, Citibank, N.A., as Priority Lien Term Facility Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.5 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.33	Priority Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.34	Additional Priority Lien Intercreditor Agreement, dated as of November 29, 2016, by and among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Wilmington Trust, National Association, as Notes Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.35	Consent and Acknowledgement, dated as of November 29, 2016, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as Applicable Second Lien Agent, and EP Energy LLC, with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.2 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.36	Consent and Acknowledgement, dated as of November 29, 2016, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as Applicable Second Lien Agent, and EP Energy LLC, with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.3 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.37	Consent and Acknowledgement, dated as of February 6, 2017, by Wilmington Trust, National Association, as new Term Facility Agent and Applicable Second Lien Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as prior Term Facility Agent and prior Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and EP Energy LLC, with respect to the Priority Lien Intercreditor Agreement, dated as of August 24, 2016 and supplemented on November 29, 2016 (Exhibit 10.1 to Company's Report on Form 8-K, filed with the SEC on February 7, 2017).

10.38	Consent and Acknowledgement, dated as of February 6, 2017, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and EP Energy LLC, with respect to the Amended and Restated Senior Lien Intercreditor Agreement, dated as of August 24, 2016 and supplemented on November 29, 2016 (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.39	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other Second-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as Term Facility Agent for the holders of the 8.00% 2025 Notes and Applicable Second Lien Agent and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on January 4, 2018).
10.40	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2025 Notes, and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on January 4, 2018).
10.41	Collateral Agreement, dated as of November 29, 2016, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on November 30, 2016).

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Exhibit No.	Exhibit Description
10.42	Collateral Agreement, dated as of February 6, 2017, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.43	Pledge Agreement, dated as of November 29, 2016, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.5 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.44	Pledge Agreement, dated as of February 6, 2017, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.45	Collateral Agreement, dated as of May 23, 2018, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Wilmington Trust, National Association, as collateral agent (Exhibit 10.2 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.46	Pledge Agreement, dated as of May 23, 2018, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Wilmington Trust, National Association, as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.47	Senior Priority Lien Intercreditor Agreement, dated as of May 23, 2018, by and among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Wilmington Trust, National Association, as Notes Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.4 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.48	Consent and Acknowledgement, dated as of May 23, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Trust, National Association, as Notes Facility Agent for holders of 8.00% Senior Secured Notes due 2024 and as Applicable Second Lien Agent, and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Additional Priority Lien Intercreditor Agreement dated as of November 29, 2016 (Exhibit 10.5 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.49	Consent and Acknowledgement, dated as of May 23, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% Senior Secured Notes due 2024, Wilmington Trust, National Association, as Term Facility Agent for the holders of the 8.00% Senior Secured Notes due 2025 and Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other Second-Priority Lien Obligations Agent for the holders of the 9.375% Senior Secured Notes due 2024 and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.6 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).

10.50	Consent and Acknowledgement, dated as of May 23, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% Senior Secured Notes due 2024, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% Senior Secured Notes due 2025, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 9.375% Senior Secured Notes due 2024, and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.7 to Company's Current Report on Form 8-K filed with the SEC on May 24, 2018).
10.51+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Russell Parker (Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.52+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Ray Ambrose (Exhibit 10.2 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.53+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Chad England (Exhibit 10.3 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.54*+	Employment Agreement dated as of May 24, 2012 by and between EP Energy Corporation and Kyle A. McCuen.
10.55+	Senior Executive Survivor Benefit Plan adopted as of May 24, 2012 (Exhibit 10.23 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).

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Exhibit No.	Exhibit Description
10.56+	Management Incentive Plan Agreement, dated as of August 30, 2013, between EP Energy Corporation and EPE Employee Holdings, LLC (Exhibit 10.31 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.57+	Form of EPE Employee Holdings, LLC Management Incentive Unit Agreement (Exhibit 10.26 to EP Energy LLC's Registration Statement on Form S-4 filed with the SEC on September 11, 2012).
10.58+	Form of Notice to MIPs Holders regarding Corporate Reorganization (Exhibit 10.33 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
10.59+	Third Amended and Restated Limited Liability Company Agreement of EPE Employee Holdings, LLC dated as of August 30, 2013 (Exhibit 10.34 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.60+	Form of EP Energy Employee Holdings II, LLC Class B Incentive Pool Program Award Agreement (Exhibit 10.37 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.61+	EP Energy Corporation 2014 Omnibus Incentive Plan, as amended and restated effective May 11, 2016 (Exhibit 10.1 to EP Energy Corporation's Current Report on Form 8-K, filed with the SEC on May 13, 2016).
10.62+	Form of Notice Stock Option Grant and Stock Option Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.39 to Company's Annual Report on Form 10-K filed with the SEC on February 27, 2014).
10.63+	Form of Notice Restricted Stock Grant and Restricted Stock Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.40 to Company's Annual Report on Form 10-K filed with the SEC on February 28, 2014).
10.64+	Form of Performance Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan. (Exhibit 10.42 to Company's Annual Report on Form 10-K filed with the SEC on February 22, 2016).
10.65+	Form of 2017 Performance Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.52 to Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
10.66+	EP Energy Corporation Employment Inducement Plan (Exhibit 10.4 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.67+	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the EP Energy Corporation Employment Inducement Plan (Exhibit 10.5 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).

10.68+	Form of Restricted Stock Grant Notice and Restricted Stock Agreement under the EP Energy Corporation Employment Inducement Plan (Exhibit 10.6 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.69+	Form of Performance Share Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018, filed with the SEC on August 9, 2018).
10.70+	Form of Performance-Based Restricted Stock Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.2 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018, filed with the SEC on August 9, 2018).
10.71	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 10.39 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.72	Addendum Agreement, dated as of September 18, 2013, to the Stockholders Agreement, between EP Energy Corporation and EP Energy Employee Holdings II, LLC (Exhibit 10.40 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.73	Form of Director and Officer Indemnification Agreement between EP Energy Corporation and each of the officers and directors thereof (Exhibit 10.41 to Amendment No. 4 to the Company's Registration Statement on Form S-1, filed with the SEC on January 6, 2014).
21.1*	Subsidiaries of EP Energy Corporation.
23.1*	Consent of Ernst & Young LLP, an independent registered public accounting firm.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit No.	Exhibit Description
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company, L.P. reserve report for EP Energy Corporation as of December 31, 2018.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

(c) Financial statement schedules

Financial statement schedules have been omitted because they are either not required or not applicable.

ITEM 16. FORM 10-K SUMMARY

None.

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SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, EP Energy Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 18th day of March 2019.

EP ENERGY CORPORATION

By: /s/ Russell E. Parker
Russell E. Parker
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 EP Energy Corporation and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Russell E. Parker Russell E. Parker	President, Chief Executive Officer and Director (Principal Executive Officer)	March 18, 2019
/s/ Kyle A. McCuen Kyle A. McCuen	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 18, 2019
/s/ Alan R. Crain, Jr. Alan R. Crain, Jr.	Chairman of the Board	March 18, 2019
/s/ Gregory A. Beard Gregory A. Beard	Director	March 18, 2019
/s/ Scott R. Browning Scott R. Browning	Director	March 18, 2019
/s/ Wilson B. Handler Wilson B. Handler	Director	March 18, 2019
/s/ John J. Hannan John J. Hannan	Director	March 18, 2019
/s/ J. Barton Kalsu J. Barton Kalsu	Director	March 18, 2019
/s/ Rajen Mahagaokar Rajen Mahagaokar	Director	March 18, 2019
/s/ Robert C. Reeves Robert C. Reeves	Director	March 18, 2019
/s/ Giljoon Sinn Giljoon Sinn	Director	March 18, 2019

/s/ Robert M. Tichio		
Robert M. Tichio	Director	March 18, 2019
/s/ Donald A. Wagner		
Donald A. Wagner	Director	March 18, 2019
/s/ Rakesh Wilson		
Rakesh Wilson	Director	March 18, 2019

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