WHITING PETROLEUM CORP
Form 10-K
February 28, 2019

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

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

For the fiscal year ended December 31, 2018

or

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

For the transition period from _______________ to _______________

Commission file number: 001 31899

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20 0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290 2300 (Zip code)

(303) 837 1661
(Registrant’s telephone number, including area code)

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

Common Stock, $0.001 par value	New York Stock Exchange
(Title of each class)	(Name of each exchange on which registered)

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10 K or any amendment to this Form 10 K.

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

Large accelerated filer	Smaller reporting company
Accelerated filer	Emerging growth company
Non accelerated filer	

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

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2018: $4,798,000,000.

Number of shares of the registrant's common stock outstanding at February 20, 2019: 91,268,384 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2019 Annual Meeting of Stockholders are incorporated by reference into Part III.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we”, “us”, “our” or “ours” when used in this Annual Report on Form 10 K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this Annual Report on Form 10 K:

“3 D seismic” Geophysical data that depict the subsurface strata in three dimensions. 3 D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2 D, or two-dimensional, seismic.

“ASC” Accounting Standards Codification.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

“Bcf” One billion cubic feet, used in reference to natural gas.

“BOE” One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

“Btu” or “British thermal unit” The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

“CO2” Carbon dioxide.

“completion” The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

“costless collar” An option position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

“deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

“development well” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

“dry hole” A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

“EOR” Enhanced oil recovery.

“exploratory well” A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

“extension well” A well drilled to extend the limits of a known reservoir.

“FASB” Financial Accounting Standards Board.

“field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition”

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are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

“GAAP” Generally accepted accounting principles in the United States of America.

“gross acres” or “gross wells” The total acres or wells, as the case may be, in which a working interest is owned.

“ISDA” International Swaps and Derivatives Association, Inc.

“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil, NGLs or other liquid hydrocarbons.

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas.

“MMBbl” One million barrels of oil, NGLs or other liquid hydrocarbons.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units, used in reference to natural gas.

“MMcf” One million cubic feet, used in reference to natural gas.

“MMcf/d” One MMcf per day.

“net acres” or “net wells” The sum of the fractional working interests owned in gross acres or wells, as the case may be.

“net production” The total production attributable to our fractional working interest owned.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“PDNP” Proved developed nonproducing reserves.

“PDP” Proved developed producing reserves.

“plug-and-perf technology” A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the casing perforations into the formation within that stage.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

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“pre-tax PV10%” The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated lease operating expense, production taxes and future development costs, using costs as of the date of estimation without future escalation and using an average of the first-day-of-the-month price for each of the 12 months within the fiscal year, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. Refer to the footnote to the Proved Reserves table in Item 1. “Business” of this Annual Report on Form 10 K for more information.

“prospect” A property on which indications of oil or gas have been identified based on available seismic and geological information.

“proved developed reserves” Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and
b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

“proved undeveloped reserves” or “PUDs” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

“reasonable certainty” If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and,

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as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

“recompletion” An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

“reserves” Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“resource play” An expansive contiguous geographical area with known accumulations of crude oil or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.

“royalty” The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

“royalty interest” An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

“SEC” The United States Securities and Exchange Commission.

“standardized measure of discounted future net cash flows” or “Standardized Measure” The discounted future net cash flows relating to proved reserves based on the average price during the 12 month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period (unless prices are defined by contractual arrangements, excluding escalations based upon future conditions); current costs and statutory tax rates (to the extent applicable); and a 10% annual discount rate.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

“workover” Operations on a producing well to restore or increase production.

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. We were incorporated in the state of Delaware in 2003 in connection with our initial public offering.

Since our inception, we have built a strong asset base through a combination of property acquisitions, development of proved reserves and exploration activities. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties, such as the acquisition discussed below under "Acquisitions and Divestitures," and exploring other basins where we can apply our existing knowledge and expertise to build production and add proved reserves. As a result of lower crude oil prices during 2016 and 2017, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2018, we continued to focus on high-return projects in our asset portfolio that added production and reserves while generating free cash flows from operations. In 2019, we expect to continue to closely align our capital spending with cash flows generated from operations while focusing on developing our large resource play in the Williston Basin of North Dakota and Montana. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under "Acquisitions and Divestitures".

As of December 31, 2018, our estimated proved reserves totaled 520.1 MMBOE and our 2018 average daily production was 128.0 MBOE/d, which results in an average reserve life of approximately 11.1 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2018 with the corresponding pre-tax PV10% values, our fourth quarter 2018 average daily production rates, and our total standardized measure of discounted future net cash flows as of December 31, 2018:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2018 Average Daily Production (MBOE/d)
Northern Rocky Mountains (3)	255.8	105.8	678.0	474.6	54%	$ 5,145	111.5
Central Rocky Mountains (4)	25.1	5.2	47.6	38.2	66%	296	17.8
Other (5)	6.1	0.3	5.5	7.3	84%	62	0.7
Total	287.0	111.3	731.1	520.1	55%	$ 5,503	130.0
Discounted Future Income Tax Expense						(297)	
Standardized Measure of Discounted Future Net Cash Flows						$ 5,206	

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from an oil price of $65.56 per Bbl and a gas price of $3.10 per MMBtu, which were calculated using an average of the first-day-of-the-month price for each month within the 12 months ended December 31, 2018 as required by current SEC and FASB guidelines.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (the "Standardized Measure"), which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size

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and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the Standardized Measure. Our pre-tax PV10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

(3) Includes oil and gas properties located in Montana and North Dakota.

(4) Includes oil and gas properties located in Colorado.

(5) Primarily includes non-core oil and gas properties located in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming.

During 2018, we incurred $832 million in exploration and development ("E&D") expenditures, including $819 million for the drilling of 211 gross (121.7 net) wells. All of these new wells resulted in productive completions.

Our current 2019 E&D budget is a range of $800 million to $840 million, which we expect to fund substantially with net cash provided by our operating activities and cash on hand. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate, adjust our E&D budget accordingly, enter into agreements with industry partners, divest certain oil and gas property interests, adjust borrowings outstanding under our credit facility or access the capital markets as necessary.

Acquisitions and Divestitures

2018 Acquisitions and Divestitures. In July 2018, we completed the acquisition of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The producing properties had estimated proved reserves of 25.7 MMBOE as of the acquisition date, 84% of which were crude oil and NGLs.

There were no significant divestitures during the year ended December 31, 2018.

2017 Acquisitions and Divestitures. In January 2017, we completed the sale of our 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and our 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments).

In September 2017, we completed the sale of our interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, (the "FBIR Assets") for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. The properties spanned approximately 29,600 net developed acres and consisted of estimated proved reserves of 32 MMBOE as of December 31, 2016, representing 5% of our proved reserves as of that date. The FBIR Assets generated 7% (or 8.3 MBOE/d) of our August 2017 average daily production.

There were no significant acquisitions during the year ended December 31, 2017.

Business Strategy

Our goal is to generate meaningful growth in shareholder value through the development, acquisition and exploration of oil and gas projects with attractive rates of return on capital. Specifically, we have focused, and plan to continue to focus, on the following:

Efficiently Developing Existing Properties. The development of our large resource play at our Williston Basin project in North Dakota and Montana has become our central objective. We have assembled approximately 785,800 gross (470,400 net) developed and undeveloped acres in this area, on which we had five drilling rigs operating as of December 31, 2018. During 2018, we completed and brought on production 122 gross (82 net) operated Bakken and Three Forks wells in the Williston Basin. Under our current 2019 capital program, we expect to put on production approximately 146 gross operated wells in this area during the year.

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Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of our exposure to commodity price volatility. We have historically funded our acquisition and growth activity through a combination of internally generated cash flows, equity and debt issuances, bank borrowings and certain oil and gas property divestitures, as appropriate, to maintain our financial position. As a result of lower crude oil prices in 2016 and 2017, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2018, we continued to focus on high-return projects in our asset portfolio that will add production and reserves while generating free cash flows from operations. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt or fund our E&D expenditures. For example, during 2016 and 2017 we sold a large number of oil and gas properties and other related assets that no longer matched the profile of properties we desire to own. In addition, to support cash flow generation on our existing properties and help ensure expected cash flows from newly acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and swaps to provide an attractive base commodity price level. As of February 20, 2019, we had derivative contracts covering the sale of approximately 37% of our forecasted 2019 oil production.

Growing Through Accretive Acquisitions. Since 2003, we have completed 22 separate significant acquisitions of producing properties for total estimated proved reserves of 470.9 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, business development, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, closing purchases and effectively managing the properties we acquire. We intend to selectively pursue the acquisition of properties that are complementary to our core operating areas, as well as explore opportunities in other basins where we can apply our existing knowledge and expertise to build production and add proved reserves.

Competitive Strengths

We believe that our key competitive strengths lie in our focused asset portfolio, our experienced management and technical teams and our commitment to the effective application of new technologies.

Focused, Long-Lived Asset Base. As of December 31, 2018, we had interests in 4,996 gross (2,097 net) productive wells on approximately 881,600 gross (539,300 net) developed acres across our geographical areas. We believe the concentration of our operated assets presents us with multiple opportunities to successfully execute our business strategy by enabling us to leverage our technical expertise and take advantage of operational efficiencies. Our proved reserve life is approximately 11.1 years based on year-end 2018 proved reserves and 2018 production.

Experienced Management and Technical Teams. Our management team averages 23 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, our team of acquisition professionals has an average of 25 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties. During 2018, we reorganized the management of our Williston Basin project into three separate geographically focused asset teams allowing for a more focused development of our primary assets.

Commitment to Technology. In each of our core operating areas, we have accumulated extensive engineering, operational, geologic and geophysical technical knowledge. Our technical team has access to an abundance of digital well log, seismic, completion, production and other subsurface information, which is analyzed in order to accurately and efficiently characterize the anticipated performance of our oil and gas reservoirs. In addition, our information systems enable us to update our production databases through field automation. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

We continue to advance our completion techniques by utilizing customized, right-sized completion designs based on calibrated models for each of our prospect areas, using multivariate analysis to understand which completion factors most significantly impact the results in each area, and piloting and adopting the latest completion technologies available. Such customized designs utilize the optimum volume of proppant, fluids and frac stages, allowing us to increase well performance while reducing cost. We plan to continue to use right-sized completion designs on wells we drill in 2019, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and 3 D bit cutter technology to reduce time-on-location and total well cost.

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Proved Reserves

Our estimated proved reserves as of December 31, 2018 are summarized by core area in the table below. Refer to “Reserves” in Item 2 of this Annual Report on Form 10 K for information relating to the uncertainties surrounding these reserve categories.

	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (1) (in millions)
Northern Rocky Mountains (2)						
PDP	170.9	78.1	486.0	330.0	69%	
PDNP	1.5	0.7	5.4	3.1	1%	
PUD	83.4	27.0	186.6	141.5	30%	
Total proved	255.8	105.8	678.0	474.6	100%	$ 1,664
Central Rocky Mountains (3)						
PDP	16.5	3.6	32.7	25.6	67%	
PUD	8.6	1.6	14.9	12.6	33%	
Total proved	25.1	5.2	47.6	38.2	100%	$ 177
Other (4)						
PDP	5.6	0.3	3.9	6.5	89%	
PDNP	0.4	-	1.2	0.6	8%	
PUD	0.1	-	0.4	0.2	3%	
Total proved	6.1	0.3	5.5	7.3	100%	$ 13
Total Company						
PDP	193.0	82.0	522.6	362.1	69%	
PDNP	1.9	0.7	6.6	3.7	1%	
PUD	92.1	28.6	201.9	154.3	30%	
Total proved	287.0	111.3	731.1	520.1	100%	$ 1,854

(1) Estimated future capital expenditures incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.
(2) Includes oil and gas properties located in Montana and North Dakota.
(3) Includes oil and gas properties located in Colorado.
(4) Primarily includes non-core oil and gas properties located in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming.

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline or rail takeaway. In areas where there is no practical access to gathering pipelines, oil is trucked or transported to terminals, market hubs, refineries or storage facilities. The tables below present percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2018, 2017 and 2016. We believe that the loss of any individual purchaser

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would not have a long-term material adverse impact on our financial position or results of operations, as alternative customers and markets for the sale of our products are readily available in the areas in which we operate.

Year Ended December 31, 2018	
United Energy Trading, LLC	17 %
Tesoro Crude Oil Co	14 %
Philips 66 Company	11 %

Year Ended December 31, 2017	
Tesoro Crude Oil Co	18 %

Year Ended December 31, 2016	
Tesoro Crude Oil Co	15 %
Jamex Marketing LLC	12 %

Title to Properties

Our properties are subject to customary royalty interests, liens securing indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also collateralized by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory rights or title to all of our producing properties. As is customary in the oil and gas industry, limited investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

The oil and gas industry is a highly competitive environment for acquiring properties, obtaining investment capital, securing oil field goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our resources permit. In addition, the unavailability or high cost of drilling rigs or other equipment and services could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Regulation

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations that we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, NGLs and natural gas within its jurisdiction.

Currently, none of our total production volumes are produced from offshore leases, however, some of our prior offshore operations were conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the “BOEM”). The present value of our future abandonment obligations associated with offshore properties was $38 million as of December 31, 2018. We are therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act.

Among other things, BOEM regulations establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases.

The BOEM also establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by the BOEM and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

Regulation of Sale and Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices, however, Congress could reenact price controls or enact other legislation in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. The FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The most recent mandatory five-year review period resulted in a 2015 order from the FERC for the index to be based on Producer Price Index for Finished Goods (the "PPI-FG") plus a 1.23% adjustment for the five-year period from July 1, 2016 through June 30, 2021. This represents a decrease from the PPI-FG plus 2.65% adjustment from the prior five-year period. The FERC determined that it would now use a calculation based on what it determined to be a superior data source, reflecting actual cost-of-service data as opposed to the accounting data historically used as a proxy for such information under the prior index methodology. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. In addition, the FERC has emergency authority under the Interstate Commerce Act to intervene and direct priority use of oil pipeline transportation capacity, and the FERC exercised this authority over a specific pipeline in February 2014 in response to significant disruptions in the supply of propane. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Transportation and safety of oil and hazardous liquid is subject to regulation by the Department of Transportation (the "DOT") under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. The Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency within the DOT, enforces regulations on all interstate liquids transportation and some intrastate liquids transportation. PHMSA does not enforce the regulations in states that are capable of enforcing the same regulations themselves. The effect of regulatory changes under the DOT and their effect on interstate and intrastate oil and hazardous liquid transportation will not affect our operations in any way that is of material difference from those of our competitors.

A portion of our crude oil production may be shipped to market centers using rail transportation facilities owned and operated by third parties. The DOT and PHMSA establish safety regulations relating to crude-by-rail transportation. In addition, third-party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the DOT, the Federal Railroad Administration (the "FRA") of the DOT, the Occupational Safety and Health Administration and other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to regulate movement of hazardous materials in ways not preempted by federal law.

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. In response to train derailments occurring in the United States and Canada in 2013 and 2014, U.S. regulators have taken a number of actions to address the safety risks of transporting crude oil by rail.

In February 2014, the DOT issued an emergency order requiring all persons to ensure crude oil is properly tested and classed prior to offering such product into transportation, and to assure all shipments by rail of crude oil be handled as a Packing Group I or II hazardous material. Also in February 2014, the Association of American Railroads entered into a voluntary agreement with the DOT to implement certain restrictions around the movement of crude oil by rail. In May 2014 (and extended indefinitely in May 2015), the DOT issued an Emergency Restriction/Prohibition Order requiring each railroad carrier operating trains transporting 1,000,000 gallons or more of Bakken crude oil to provide notice to state officials regarding the expected movement of the trains through the counties in each state. The PHMSA and FRA have also issued safety advisories and alerts regarding oil transportation and have issued a report focused on the increased volatility and flammability of Bakken crude oil as compared with other crudes in the U.S. In May 2015, PHMSA issued new rules applicable to “high-hazard flammable trains”, defined as a continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed throughout a train. Among other requirements, the new rules require enhanced standards for newly constructed tank cars and retrofitting of existing tank cars, restricted operating speeds, a documented testing and sampling program, and routine assessments that evaluate certain safety and security factors. In December 2015, the Fixing America’s Surface Transportation (“FAST”) Act became law, further extending PHMSA’s authority to improve the safety of transporting flammable liquids by rail and pursuant to which new regulations phasing out the use of certain older rail cars were finalized in August 2016. In June 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety (“PIPES”) Act became law. The PIPES Act strengthens PHMSA’s safety authority, including an expansion of its ability to issue emergency orders, which was adopted by rule in October 2016. PHMSA continues to review further potential new safety regulations under the PIPES Act and the FAST Act.

We do not currently own or operate rail transportation facilities or rail cars. However, the adoption of any regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the U.S., the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows. The effect of any such regulatory changes will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Transportation, Storage, Sale and Gathering of Natural Gas

The FERC regulates the transportation and, to a lesser extent, the sale of natural gas for resale in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC’s jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances.

The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. Regulations implemented by the FERC could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry has historically been heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Transportation and safety of natural gas is subject to regulation by the DOT under the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. In addition, intrastate natural gas

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transportation is subject to enforcement by state regulatory agencies and PHMSA enforces regulations on interstate natural gas transportation. State regulatory agencies can also create their own transportation and safety regulations as long as they meet PHMSA's minimum requirements. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Likewise, the effect of regulatory changes by the DOT and their effect on interstate natural gas transportation will not affect our operations in any way that is of material difference from those of our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

In October 2015, a failure at an underground natural gas storage facility in Southern California prompted PHMSA to issue an advisory bulletin reminding owners and operators of underground storage facilities to review operations, identify the potential for facility leaks and failures, and to review and update emergency plans. The State of California proclaimed the underground natural gas storage facility an emergency situation in January 2016. A federal task force was also convened to make recommendations to help avoid such failures. An interim final rule of PHMSA became effective in January 2017 which adopted certain specific industry recommended practices into Part 192 of the Federal Pipeline Safety Regulations. PHMSA later reopened the post-promulgation comment period through November 2017 in response to petitions for reconsideration and has stated it would consider such comments further when it adopts a final rule. Under the interim final rule, if an operator fails to take any measures recommended it would need to justify in its written procedures why the measure is impracticable and unnecessary. PHMSA regulations had previously covered much of the surface piping up to the wellhead at underground natural gas storage facilities served by pipelines and did not extend in part to the "downhole" portion of these facilities. The adopted requirements cover design, construction, material, testing, commissioning, reservoir monitoring and recordkeeping for existing and newly constructed underground natural gas storage facilities as well as procedures and practices for newly constructed and existing underground natural gas storage facilities, such as operations, maintenance, threat identification, monitoring, assessment, site security, emergency response and preparedness, training, recordkeeping and reporting. These regulations and any further increased attention to and requirements for underground storage safety and infrastructure by state and federal regulators that may result from this incident will not affect us in a way that materially differs from the way it affects other natural gas producers.

Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences; restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities; limit or prohibit project siting, construction or drilling activities on certain lands located within wilderness, wetlands, ecologically sensitive and other protected areas; require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits; and impose substantial liabilities for unauthorized pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in compliance, in all material respects, with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

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President Trump has indicated that he would work to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue or any new legislation Congress may pass with the goal of reducing environmental statutory or regulatory requirements may be challenged in court. In addition, various state laws and regulations (and permits issued thereunder) will be unaffected by federal changes unless and until the state laws and corresponding permits are similarly changed, and any judicial review is completed.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), and comparable state laws impose strict joint and several liability, without regard to fault or the legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where a release occurred and anyone who disposed of or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may be regulated as "hazardous substances". Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites where these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on, under or from the properties owned or leased by us or on, under or from other locations where such substances have been taken for recycling or disposal. In addition, many of these owned and leased properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired or leased the property or business, and if the problem itself is not discovered until years later. Our properties, adjacent affected properties, offsite disposal facilities and substances disposed or released on them may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;
- to clean up contaminated property, including contaminated groundwater;
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators; or
- to pay some or all of the costs of any such action.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee, permittee or holder of a right of use and easement of the area in which an offshore facility is located. OPA establishes a liability limit for onshore facilities of $350 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75 million per spill damages. These limits do not apply if the spill is caused by a responsible party's gross negligence or willful misconduct; the spill resulted from a responsible party's violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA also requires the lessee or permittee of the offshore area in which a

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covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President may increase the amount of financial responsibility required under OPA by up to $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. We generate solid and hazardous wastes that are subject to RCRA and comparable state laws. Drilling fluids, produced water and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA, requesting it to reconsider the RCRA exemption for exploration, production and development wastes. In May 2016, several environmental groups sued the EPA for failing to update its rules for management of oil and gas drilling waste under RCRA. The petitioners requested that the EPA revise its regulations for waste materials generated as a result of oil and gas exploration and production activities. The petitioners claimed that the EPA has not reviewed or revised its regulations for management of wastes from oil and gas exploration and production operations since 1988, even though the statute requires the EPA to review and, if necessary, revise the regulations every three years. In December 2016, the court entered a Consent Decree resolving the litigation. Under the Consent Decree, the EPA has agreed to propose no later than March 15, 2019 a rulemaking for revision of the regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. The EPA has not announced whether the December 2018 government shutdown will impede its ability to meet that deadline. In the event that the EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any such change in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes may be regulated by state agencies as solid waste. Also, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes (as they are presently classified) to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, as amended ("CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state waters or other waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The EPA had regulations under the authority of CWA that required certain oil and gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the Energy Policy Act of 2005 nullified most of the EPA regulations that required storm water permitting of oil and gas construction projects. There are still some state and federal rules that regulate the discharge of storm water from some oil and gas construction projects. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations. In Section 40 CFR 112 of the regulations, the EPA promulgated the Spill Prevention, Control and Countermeasure regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards.

Air Emissions. The Federal Clean Air Act, as amended (the “CAA”), and comparable state laws regulate emissions of various air pollutants from various industrial sources through air emissions permitting programs and also impose other monitoring and reporting

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requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining pre-construction and operating permits and approvals for air emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. For example, in 2012, the EPA finalized rules establishing new air emission controls for oil and natural gas production operations. Specifically, the EPA's rule includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. Among other things, these standards require the application of reduced emission completion techniques associated with the completion of newly drilled and fractured wells in addition to existing wells that are refractured. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. These rules could require a number of modifications to operations at certain of our oil and gas properties including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

The EPA announced in 2015 that it would directly regulate methane emissions from oil and natural gas wells for the first time as part of President Obama's Climate Action Plan. As part of this strategy, in May 2016, the EPA issued three final rules. The EPA issued a final rule that updated the New Source Performance Standards to add requirements that the oil and gas industry reduce emissions of greenhouse gases and to cover additional equipment and activities in the oil and gas production chain. The final rule sets emissions limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. This rule applies to new, reconstructed and modified processes and equipment. This rule also expands the volatile organic compound emissions limits to hydraulically fractured oil wells and equipment used across the industry that was not regulated in the 2012 rules. The rule also requires owners and operators to find and repair leaks, also known as "fugitive emissions." The EPA also issued a final rule known as the Source Determination Rule, which is intended to clarify when multiple pieces of equipment and activities in the oil and gas industry must be deemed a single source when determining whether major source permitting programs apply under the prevention of significant deterioration, nonattainment new source review preconstruction and operation permit programs under Title V of the CAA ("Title V"). The final rule defines the term "adjacent" to clarify that equipment and activities in the oil and gas sector that are under common control will be considered part of the same source if they are located near each other – specifically, if they are located on the same site, or on sites that share equipment and are within one quarter of a mile of each other. This rule applies to equipment and activities used for onshore oil and natural gas production, and for natural gas processing. It does not apply to offshore operations. Finally, the EPA also issued a final Federal Implementation Plan ("FIP") for Indian country, which implements the minor new source review program in Indian country for oil and natural gas production. The FIP will be used instead of site-specific minor new source review preconstruction permits in Indian country and incorporates emissions limits and other requirements from eight federal air standards, including the final New Source Performance Standard, Subpart OOOOa. Requirements of the FIP apply throughout Indian country, except non-reservation areas, unless a tribe or the EPA demonstrates jurisdiction for those areas.

Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

In 2016, the EPA also issued the first draft of an Information Collection Request, seeking a broad range of information on the oil and gas industry, including: how equipment and emissions controls are, or can be, configured, what installing those controls entails and the associated costs. This includes information on natural gas venting that occurs as part of existing processes or maintenance activities, such as well and pipeline blowdowns, equipment malfunctions and flashing emissions from storage tanks.

In June 2017, the EPA proposed staying the final rule implementing certain of the new oil and gas standards for two years while it reconsiders the rules. In November 2017, the EPA issued a notice of data availability for the proposed stay of the rules, with a comment period closing on December 8, 2017. On October 15, 2018, the EPA published in the Federal Register proposed revisions to the Subpart OOOOa rules, and took public comment on those revisions until December 17, 2018. The EPA is still considering the comments filed on the proposed rule, and has not yet finalized the revisions to Subpart OOOOa.

Certain states have adopted, or are considering, regulations covering methane releases for oil and gas operations. Colorado has adopted regulations for methane from oil and gas operations.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of mainly water and sand plus a de minimis amount of chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of North Dakota, Montana and Colorado and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions, however, the EPA also issued guidance in 2014 for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

In December 2016, the EPA released a final report on the potential impacts of oil and gas fracturing activities on the quality and quantity of drinking water resources in the United States. In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for the oil and gas extraction category which would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities accepting oil and gas extraction wastewater. The EPA is collecting data and information regarding the extent to which these facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of the facilities, the environmental impacts of discharges and other information. In addition to the EPA, other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office, the U.S. Department of Interior and the White House Council for Environmental Quality.

In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Some states have adopted, and other states are considering adopting, regulations that could ban, restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, in June 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permitting requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt, and some have adopted, ordinances within their jurisdictions restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing. In 2018, Colorado considered, but did not adopt, a ballot measure that would have established a 2,500-foot setback for oil and gas operations from certain areas. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities and the calculation of our reserves.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study, as well as subsequent studies and reports, may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Further, in May 2014, the EPA published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. On July 11, 2014, the EPA extended the public comment period for the rulemaking to September 18, 2014. The EPA has not yet taken further action with respect to this rule. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties. In addition, we may be required to disclose information of third parties, which may be inaccurate or which we may be contractually prohibited from disclosing, which could also subject us to penalties.

Global Warming and Climate Change. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. Based on these findings,

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the EPA has adopted and implemented regulations that restrict emissions of GHG under existing provisions of the CAA, including rules that limit emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect in January 2011. In June 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (the "PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first becoming subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis. We believe that we are in compliance with all substantial applicable emissions requirements.

In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions.

In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. On November 18, 2016, the EPA extended the public comment period for the rulemaking to December 16, 2016. The proposed rule has not yet been finalized.

In accordance with President Obama's Climate Action Plan, in August 2015, the EPA issued a rule to reduce carbon emissions from electric generating units. The rule, commonly called the "Clean Power Plan", requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2022, with the reductions to be fully phased in by 2030. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 32% from 2005 levels. States are given substantial flexibility in meeting their emission reduction targets and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units or renewable energy alternatives. Several industry groups and states have challenged the Clean Power Plan in the Court of Appeals for the D.C. Circuit, and in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it is being challenged in court. On March 28, 2017, the Trump Administration issued an executive order directing the EPA to review the Clean Power Plan. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan. On August 18, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule as a replacement to the Clean Power Plan. The ACE rule was published in the Federal Register on August 31, 2018, and comments were accepted until October 31, 2018. The EPA has not yet issued a final ACE rule, although several states have announced their intention to challenge the rule once it is made final.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA has issued the Subpart OOOOa regulations that limit emissions of GHG associated with our operations, which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil, NGLs and natural gas that we produce. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA") and the Coastal Zone Management Act ("CZMA"), require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the

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marine, coastal or human environment. Similarly, NEPA requires the U.S. Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and potentially an environmental impact statement. Recent federal court cases involving natural gas pipelines have involved challenges to the sufficiency of the evaluation of climate change impacts in environmental impact statements prepared under NEPA. The CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the U.S. Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Employees

As of January 31, 2019, we had approximately 755 full-time employees, including 15 senior level geoscientists and 60 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our annual reports on Form 10 K, quarterly reports on Form 10 Q and current reports on Form 8 K, including exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC.

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Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10 K, before making an investment decision with respect to our securities. In the event of the occurrence, reoccurrence, continuation or increased severity of any of the risks described below, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the level of global oil and natural gas inventories;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political and economic conditions, including embargoes and sanctions, in oil-producing countries or affecting other oil-producing activity, such as the U.S. imposed sanctions on Venezuela and Iran and conflicts in the Middle East;
- developments of United States energy infrastructure;
- the level of global oil and natural gas exploration and production activity;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the effects of global and domestic credit, financial and economic issues;
- weather conditions;
- technological advances affecting energy consumption;
- current and anticipated changes to domestic and foreign governmental regulations, including those expected from the current U.S. administration;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- the price and availability of alternative fuels; and
- acts of force majeure.

Moreover, government regulations, such as regulation of oil and natural gas gathering and transportation, can adversely affect commodity prices in the long term.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. Also, prices for crude oil and prices for natural gas do not necessarily move in tandem. Declines in oil or natural gas prices would not only reduce revenue, but could also reduce the amount of oil and natural gas that we can economically produce and therefore potentially lower our oil and gas reserve quantities. If the oil and natural gas industry experiences extended periods of low prices, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

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Substantial and extended declines in oil, NGL and natural gas prices have resulted and may continue to result in impairments of our proved oil and gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending, sell assets or borrow to fund any such shortfall. Lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement.

Lower commodity prices may also make it more difficult for us to comply with the covenants and other restrictions in the agreements governing our debt as described under the risk factor entitled “The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.”

Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploration, development and production activities. Our oil and natural gas exploration and development activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. 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. Refer to the risk factor entitled “Reserve estimates depend on many assumptions that may turn out to be inaccurate...” for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including, but not limited to, the following:

- substantial or extended declines in oil, NGL and natural gas prices, which impacted our decision to cease additional development activity at our Redtail field;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits by state agencies or on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- pipeline takeaway and refining and processing capacity;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms; and
- title problems.

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Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2018, we had $2.3 billion of senior notes and $562 million of convertible senior notes outstanding. We had no borrowings and $2 million in letters of credit outstanding under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit facility with $1.75 billion of available borrowing capacity. We are allowed to incur additional indebtedness, provided that we meet certain requirements in the indentures governing our senior notes and Whiting Oil and Gas' credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including, but not limited to:

- making it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under Whiting Oil and Gas' credit agreement and the indentures governing our senior notes and convertible senior notes;
- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement is subject to certain rate variability;
- making us more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices; and
- reducing our borrowing base when oil and natural gas prices decline and our ability to maintain compliance with our financial covenants becomes more difficult, which may reduce or eliminate our ability to fund our operations.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. In addition, if we are in default under the agreements governing our indebtedness, we would not be able to pay dividends on our capital stock. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is redetermined on May 1 and November 1 of each year, and may be the subject of special redeterminations described in such credit agreement based on an evaluation of our oil and gas reserves. Because oil and gas prices are principal inputs into the valuation of our reserves, if oil and gas prices decline, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas' credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock or debt securities, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

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If we cannot make scheduled payments on our indebtedness or otherwise fail to comply with the covenants and other restrictions in the agreements governing our debt, we will be in default and the lenders under Whiting Oil and Gas' credit agreement and the holders of our senior notes and convertible senior notes could declare all outstanding principal and interest to be due and payable. Additionally, the lenders under Whiting Oil and Gas' credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings, and we could be forced into bankruptcy or liquidation. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our financial position and results of operations. Further, failing to comply with the financial and other restrictive covenants in Whiting Oil and Gas' credit agreement and the indentures governing our senior notes and convertible senior notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior notes and convertible senior notes and Whiting Oil and Gas' credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends or make other distributions or repurchase or redeem our capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- sell assets;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts; and
- create unrestricted subsidiaries.

In addition, Whiting Oil and Gas' credit agreement requires us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. Also, the indentures under which we issued our senior notes restrict us from incurring additional indebtedness and making certain restricted payments, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1.0. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior notes and convertible senior notes, Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us. Furthermore, if we were unable to repay the amounts due and payable under Whiting Oil and Gas' credit agreement, those lenders could proceed against the collateral granted to them to secure that indebtedness. In the event that our lenders or noteholders accelerate the repayment of our borrowings, we and our subsidiaries

may not have sufficient assets or be able to borrow sufficient funds to repay or refinance that indebtedness. Also, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

A large portion of our producing properties are concentrated in the Williston Basin project in North Dakota and Montana, making us vulnerable to risks associated with operating in one major geographic area.

A large portion of our producing properties are geographically concentrated in the Williston Basin project in North Dakota and Montana. At December 31, 2018, approximately 91% of our total estimated proved reserves were attributable to properties located in this area. Because of this concentration in a limited geographic area, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, (ii) the availability of rigs, equipment, oilfield services, supplies and labor, (iii) the availability of processing and refining facilities and (iv) infrastructure capacity. In addition, our operations in the Williston Basin may be adversely affected by severe weather events such as floods, blizzards, ice storms and tornadoes, which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in a limited geographic area also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations and cash flows.

If oil, NGL and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews (which may include depressed oil, NGL and natural gas prices and the continuing evaluation of development plans, production data, economics and other factors) we may be required to write down the carrying value of our oil and gas properties. For example, we recorded an $835 million impairment charge during 2017 for the partial write-down of the Redtail field in Colorado. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period recognized.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of mainly water and sand plus a de minimis amount of chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of North Dakota, Montana and Colorado and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions, however, the U.S. Environmental Protection Agency (the “EPA”) also issued guidance in 2014 for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

In December 2016, the EPA released a final report on the potential impacts of oil and gas fracturing activities on the quality and quantity of drinking water resources in the United States. In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for the oil and gas extraction category which would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities accepting oil and gas extraction wastewater. The EPA is collecting data and information regarding the extent to which these facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of the facilities, the environmental impacts of discharges and other information. In addition to the EPA, other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office, the U.S. Department of Interior and the White House Council for Environmental Quality.

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In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Some states have adopted, and other states are considering adopting, regulations that could ban, restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, in June 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permitting requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt, and some have adopted, ordinances within their jurisdictions restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing. In 2018, Colorado considered, but did not adopt, a ballot measure that would have established a 2,500-foot setback for oil and gas operations from certain areas. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities and the calculation of our reserves.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study, as well as subsequent studies and reports, may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Further, in May 2014, the EPA published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties. In addition, we may be required to disclose information of third parties, which may be inaccurate or which we may be contractually prohibited from disclosing, which could also subject us to penalties.

Refer to "Hydraulic Fracturing" in Item 2 of this Annual Report on Form 10 K for more information on hydraulic fracturing.

We have entered into physical delivery contracts and do not expect to be able to deliver all the oil required under such contracts and, as a result, we expect we will be required to make deficiency payments.

As of December 31, 2018, we had two physical delivery contracts which require us to deliver fixed volumes of crude oil. One of these contracts is tied to oil production at our Sanish field in Mountrail County, North Dakota, and the other is tied to oil production at our Redtail field in Weld County, Colorado. Although we believe that our production and reserves are sufficient to fulfill the delivery commitment at our Sanish field in North Dakota, if we fail to deliver the committed volumes, we would be required to pay a deficiency payment of $7.00 per undelivered barrel (subject to upward adjustment). At our Redtail field, we have determined that it is not probable that future oil production will be sufficient to meet the minimum volume requirements under the contract in this area. We expect to make periodic deficiency payments under the Redtail contract that currently total $5.08 per undelivered Bbl (subject to upward adjustment). During 2018, 2017 and 2016, total deficiency payments under this contract amounted to $37 million, $42 million and $18 million, respectively. Refer to “Properties – Delivery Commitments” for more information about these delivery contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10 K.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as the following, among others:

· historical production from the area compared with production rates from other producing areas;
· the assumed effect of governmental regulation; and
· assumptions about future prices of oil, NGLs and natural gas including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production; oil, NGL and natural gas prices; revenues; taxes; exploration and development expenditures; operating expenses; and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10 K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12 month average prices and current costs as of the date of the estimate. The 12 month average prices used for the year ended December 31, 2018 were $65.56 per Bbl of oil and $3.10 per MMBtu of natural gas. Actual future prices and costs may differ materially from those used in the estimate. If the 12 month average oil prices used to calculate our oil reserves decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2018 would have decreased by $136 million. If the 12 month average natural gas prices used to calculate our natural gas reserves decline by $0.10 per MMBtu, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2018 would have decreased by $11 million.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of internally generated cash flows, equity and debt issuances, bank borrowings, agreements with industry partners and oil and gas property divestments. We intend to finance future capital expenditures substantially with cash flow from operations and cash on hand. Our cash flow from operations and access to capital is subject to a number of variables, including, but not limited to:

· the prices at which oil and natural gas are sold;
· our proved reserves;
· the level of oil and natural gas we are able to produce from existing wells;
· the costs of producing oil and natural gas; and
· our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit agreement decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves, or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels.

We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells on these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

Risks associated with the production, gathering, transportation and sale of oil, NGLs and natural gas could adversely affect net income and cash flows.

Our net income and cash flows will depend upon, among other things, oil, NGL and natural gas production and the prices received and costs incurred to develop and produce oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, NGLs and natural gas will decrease revenues and increase expenditures. For example, accidents may occur that result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any costs incurred in connection with any such accidents that are not insured against will have the effect of reducing net income. Also, we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Refer to the risk factor entitled "Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing..." for a discussion of the uncertainty involved in the regulation of hydraulic fracturing. Also, our oil, NGL and natural gas production depends in large part on the proximity and capacity of pipeline systems and transportation facilities which are mostly owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. Similarly, curtailments or damage to pipelines and other transportation facilities used to transport oil, NGLs and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailments or damage to the gathering systems could also require finding alternative means to transport the oil, NGLs and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, in response to accidents involving rail cars carrying Bakken formation crude oil, the U.S. Department of Transportation (the "DOT") issued an emergency order in February 2014 that requires rail shippers to test the makeup of such crude oil before transporting it. This move follows the safety alert the DOT issued in January 2014 that Bakken formation crude oil is more flammable than other types of crude oil and has been followed by additional emergency orders and safety advisories and alerts. An accident involving rail cars could result in significant personal injuries and property and environmental damage. In May 2015, the Pipeline and Hazardous Material Safety Administration issued new rules applicable to “high-hazard flammable trains”, discussed in “Item 1 Business – Regulation – Regulation of Sale and Transportation of Oil” above, which could increase transportation expenses. Similarly, regulatory responses to the October 2015 failure at a Southern California underground natural gas storage facility could also lead to increased expenses for underground storage.

In addition, drilling, production and transportation of hydrocarbons bear the inherent risk of loss of containment. Potential consequences include, but are not limited to, loss of reserves, loss of production, loss of economic value associated with the affected wellbore, personal injuries and death, contamination of air, soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

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Part of our business strategy includes selling properties which subjects us to various risks.

Part of our business strategy includes selling properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. However, there is no assurance that such sales will occur in the time frames or with the economic terms we expect. Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, divestitures of our properties will reduce our proved reserves and potentially our production. We may not be able to develop, find or acquire additional reserves sufficient to replace such reserves and production from any of the properties we sell. Additionally, agreements pursuant to which we sell properties may include terms that survive closing of the sale, including but not limited to indemnification provisions, which could result in us retaining substantial liabilities.

Our acquisition activities may not be successful.

As part of our growth strategy, 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, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The risks associated with acquisitions, either completed or future acquisitions, include, but are not limited to:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and to realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures;
- we may issue additional equity or debt securities in order to fund future acquisitions; and
- we may incur losses as a result of title defects.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. Failure to drill sufficient wells in order to hold acreage will result in substantial lease renewal costs, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established on our undeveloped acreage, the underlying leases will expire. As of December 31, 2018, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 5% in 2019, 18% in 2020 and 12% in 2021. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs, completion crews and other oilfield equipment as demand for these items has increased along with the number of wells being drilled and completed. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs and other oilfield goods and services. Shortages of field personnel and other professionals, drilling rigs, completion crews, equipment or supplies or price increases could delay or adversely affect our exploration and development operations,

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which could restrict such operations or have a material adverse effect on our business, financial condition, results of operations or cash flows.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, our ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could in turn adversely affect our business or require us to remove certain proved undeveloped reserves from our proved reserve base if we are unable to drill those PUD locations within the SEC's 5 year window.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, the value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during 2018 we recorded an $8 million non-cash charge for the impairment of undeveloped oil and gas properties where we have no current or future plans to drill. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. Refer to "Acreage" in Item 2 of this Annual Report on Form 10 K for more information relating to the expiration of our rights to develop undeveloped acreage.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain indemnities from sellers for liabilities they may have created.

Our business strategy includes a continuing acquisition program. From 2004 through 2018, we completed 22 separate significant acquisitions of producing properties with a combined purchase price of $6.6 billion for estimated proved reserves as of the effective dates of the acquisitions of 470.9 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including, but not limited to, the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;

- estimates of the costs and timing of plugging and abandonment; and
- the assumption of unknown potential environmental and other liabilities, losses or costs, including for example, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

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Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our use of oil and natural gas price hedging contracts involves only a portion of our anticipated production, may limit higher revenues in the future in connection with commodity price increases and may result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas options contracts, primarily costless collars and swaps, placed with major financial institutions. As of February 20, 2019, we had contracts covering the sale of 1.1 MMBbl of oil per month for the first half of 2019 and 850 MBbl of oil per month for the second half of 2019, which represents approximately 37% of our forecasted 2019 oil production volumes. All of our oil hedges will expire by December 2019. Refer to "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of this Annual Report on Form 10 K for pricing information and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions or unwind hedging transactions we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income (loss). Consequently, we may experience significant net losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations, cause temporary declines in our oil and gas production and materially increase our operating and capital costs.

An increase in the differential or decrease in the premium between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount, but sometimes at a premium, to the relevant benchmark prices such as NYMEX. A negative difference between the benchmark price and the price received is called a differential and a positive difference is called a premium. The differential and premium may vary significantly due to market conditions, the quality and location of production and other risk factors, as demonstrated in December 2018 when our oil differentials substantially increased. We cannot accurately predict oil and natural gas differentials and premiums. Increases in the differential and decreases in the premium between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

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We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- the loss of well control;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues and increase capital expenditures.

We operate 89% of our net productive oil and natural gas wells, which represents 89% of our proved developed producing reserves as of December 31, 2018. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of our properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in, or a sustained period of low, oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use reasonable efforts to cause the operator to act in a prudent manner, we are limited in our ability to do so.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include, but are not limited to:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;

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· well spacing;
· unitization and pooling of properties; and
· taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and litigation. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations, the imposition of injunctive relief, or certain leases could be cancelled in the event that an agency refuses to issue or delays the issuance of a required permit. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Private parties, including the surface owners of properties upon which we drill, may also have the right to 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. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

President Trump has indicated that he would work to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue or any new legislation Congress may pass with the goal of reducing environmental statutory or regulatory requirements may be challenged in court. In addition, various state laws and regulations (and permits issued thereunder) will be unaffected by federal changes unless and until the state laws and corresponding permits are similarly changed, and any judicial review is completed.

Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. For example, in 2012, the EPA published final rules under the Federal Clean Air Act (the “CAA”) that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. With regard to production activities, these rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells for which well completion operations are conducted and, in particular, requiring some of these wells to use reduced emission completions, also known as “green completions”, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels.

The EPA announced in 2015 that it would directly regulate methane emissions from oil and natural gas wells for the first time as part of President Obama's Climate Action Plan. As part of this strategy, in May 2016, the EPA issued three final rules. The EPA issued a final rule that updated the New Source Performance Standards to add requirements that the oil and gas industry reduce emissions of greenhouse gases and to cover additional equipment and activities in the oil and gas production chain. The final rule sets emissions limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. This rule applies to new, reconstructed and modified processes and equipment. This rule also expands the volatile organic compound emissions limits to hydraulically fractured oil wells and equipment used across the industry that was not regulated in the 2012 rules. The rule also requires owners and operators to find and repair leaks, also known as "fugitive emissions." The EPA also issued a final rule known as the Source

Determination Rule, which is intended to clarify when multiple pieces of equipment and activities in the oil and gas industry must be deemed a single source when determining whether major source permitting programs apply under the prevention of significant deterioration, nonattainment new source review preconstruction and operation permit programs under Title V of the CAA ("Title V"). The final rule defines the term "adjacent" to clarify that equipment and activities in the oil and gas sector that are under common control will be considered part of the same source if they are located near each other – specifically, if they are located on the same site, or on sites that share equipment and are within one quarter of a mile of each other. This rule applies to equipment and activities used for onshore oil and natural gas production, and for natural gas processing. It does not apply to offshore operations. Finally, the EPA also issued a final Federal Implementation Plan ("FIP") for Indian country, which implements the minor new source review program in Indian country for oil and natural gas production. The FIP will be used instead of site-specific minor new source review preconstruction permits in Indian country and incorporates emissions limits and other requirements from eight federal air standards, including the final New Source Performance Standard, Subpart OOOOa. Requirements of the FIP apply throughout Indian country, except non-reservation areas, unless a tribe or the EPA demonstrates jurisdiction for those areas.

Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

In 2016, the EPA also issued the first draft of an Information Collection Request, seeking a broad range of information on the oil and gas industry, including: how equipment and emissions controls are, or can be, configured, what installing those controls entails and the associated costs. This includes information on natural gas venting that occurs as part of existing processes or maintenance activities, such as well and pipeline blowdowns, equipment malfunctions and flashing emissions from storage tanks.

In June 2017, the EPA proposed staying the final rule implementing certain of the new oil and gas standards for two years while it reconsiders the rules. In November 2017, the EPA issued a notice of data availability for the proposed stay of the rules, with a comment period closing on December 8, 2017. On October 15, 2018, the EPA published in the Federal Register proposed revisions to the Subpart OOOOa rules, and took public comment on those revisions until December 17, 2018. The EPA is still considering the comments filed on the proposed rule, and has not yet finalized the revisions to Subpart OOOOa.

Certain states have adopted, or are considering, regulations covering methane releases for oil and gas operations. Colorado has adopted regulations for methane from oil and gas operations.

Any increased governmental regulation could result in higher operating costs, which could in turn adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as those of the oil and gas industry in general.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and implemented regulations that restrict emissions of GHG under existing provisions of the CAA, including rules that limit emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect in January 2011. In June 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (the "PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis.

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In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions.

In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. On November 18, 2016, the EPA extended the public comment period for the rulemaking to December 16, 2016. The proposed rule has not yet been finalized.

In accordance with President Obama's Climate Action Plan, in August 2015, the EPA issued a rule to reduce carbon emissions from electric generating units. The rule, commonly called the "Clean Power Plan", requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2022, with the reductions to be fully phased in by 2030. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 32% from 2005 levels. States are given substantial flexibility in meeting their emission reduction targets and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units or renewable energy alternatives. Several industry groups and states have challenged the Clean Power Plan in the Court of Appeals for the D.C. Circuit, and in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it is being challenged in court. On March 28, 2017, the Trump Administration issued an executive order directing the EPA to review the Clean Power Plan. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan. On August 18, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule as a replacement to the Clean Power Plan. The ACE rule was published in the Federal Register on August 31, 2018, and comments were accepted until October 31, 2018. The EPA has not yet issued a final ACE rule, although several states have announced their intention to challenge the rule once it is made final.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA has issued the Subpart OOOOa regulations that limit emissions of GHG associated with our operations which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil, NGLs and natural gas that we produce. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and producing our current reserves 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.

We may be negatively impacted by litigation and legal proceedings.

We are subject from time to time, and in the future may become subject, to litigation claims. These claims and legal proceedings are typically claims that arise in the normal course of business and include, without limitation, claims relating to environmental, safety and health matters, commercial or contractual disputes with suppliers and customers, claims regarding ownership of mineral interests, including from royalty owners, claims regarding acquisitions and divestitures, regulatory matters and employment and labor matters. We may also become subject to governmental or regulatory proceedings. The outcome of such claims and legal proceedings cannot be predicted with certainty and some may be disposed of unfavorably to us. We also may not have insurance that covers such claims and

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legal proceedings. Successful claims or litigation against us for significant amounts could have a material adverse effect on our reputation, business, financial condition, results of operations and cash flows. Further, even if successful in resolving a claim or legal proceeding, such process could require the attention of members of our senior management, reducing the time they have available to devote to managing our business, and require us to incur substantial legal expenses.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Bradley J. Holly, Chairman, President and Chief Executive Officer; Charles J. Rimer, Chief Operating Officer; Michael J. Stevens, Senior Vice President and Chief Financial Officer; and Timothy M. Sulser, Chief Corporate Development and Strategy Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for additional future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, obtaining investment capital, securing oilfield goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our resources allow for. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions, such as us, to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, may be established through rulemakings. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

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We depend on computer and telecommunications systems, and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible that we, or these third parties, could incur interruptions from cyber security attacks, computer viruses or malware, or that third party service providers could cause a breach of our data. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. To our knowledge we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third party vendors and service providers.

Our convertible senior notes may adversely affect the market price of our common stock.

The market price of our common stock is likely to be influenced by our convertible senior notes. For example, the market price of our common stock could become more volatile and could be depressed by, among others:

- investors’ anticipation of the potential resale in the market of a substantial number of additional shares of our common stock received upon conversion of our convertible senior notes;
- possible sales of our common stock by investors who view our convertible senior notes as a more attractive means of equity participation in us than owning shares of our common stock; and
- hedging or arbitrage trading activity that may develop involving our convertible senior notes and our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Northern Rocky Mountains

Our Northern Rocky Mountains operations include our properties in the Williston Basin of North Dakota and Montana targeting the Bakken and Three Forks formations and encompassing approximately 785,800 gross (470,400 net) developed and undeveloped acres as of December 31, 2018. Our estimated proved reserves in the Northern Rocky Mountains as of December 31, 2018 were 474.6 MMBOE (54% oil), which represented 91% of our total estimated proved reserves and contributed 111.5 MBOE/d of average daily production in the fourth quarter of 2018.

Across our acreage in the Williston Basin, we have implemented customized, right-sized completion designs which utilize the optimum volume of proppant, fluids and frac stages to increase well performance while reducing cost. We plan to continue to use right-sized completion designs on wells we drill in 2019, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and 3-D bit cutter technology to reduce time-on-location and total well cost. As of December 31, 2018, we had five rigs active in the Williston Basin.

Central Rocky Mountains

Our Central Rocky Mountains operations include properties at our Redtail field in the Denver-Julesburg Basin ("DJ Basin") in Weld County, Colorado targeting the Niobrara and Codell/Fort Hays formations and encompassing approximately 101,000 gross (88,900 net) developed and undeveloped acres as of December 31, 2018. Our estimated proved reserves in the Central Rocky Mountains as of

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December 31, 2018 were 38.2 MMBOE (66% oil), which represented 7% of our total estimated proved reserves and contributed 17.8 MBOE/d of average daily production in the fourth quarter of 2018.

We have established production in the Niobrara "A", "B" and "C" zones and the Codell/Fort Hays formations. During 2017, we completed and brought on production a significant portion of our drilled uncompleted well inventory ("DUCs") from yearend 2016. In late 2017, based on the comparative well performance results of the DJ Basin to the Williston Basin, our management decided to concentrate development activities during 2018 in the Williston Basin. We completed 22 DUCs in our Redtail field during the first half of 2018 and have since ceased additional development activity in this area until commodity prices further recover.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of December 31, 2018, the plant was processing 30 MMcf/d.

Other

Our other operations primarily relate to non-core assets in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming. As of December 31, 2018, these properties contributed 7.3 MMBOE (84% oil) of proved reserves to our portfolio of operations, which represented 1% of our total estimated proved reserves and contributed 0.7 MBOE/d of average daily production in the fourth quarter of 2018.

Reserves

As of December 31, 2018 and 2017, all of our oil and gas reserves were attributable to properties within the United States. A summary of our proved oil and gas reserves as of December 31, 2018 and 2017 based on average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period ended December 31, 2018 and 2017, respectively) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
2018				
Proved developed reserves	194,869	82,725	529,154	365,786
Proved undeveloped reserves	92,095	28,559	201,930	154,309
Total proved reserves	286,964	111,284	731,084	520,095
2017				
Proved developed reserves	179,829	76,957	473,829	335,758
Proved undeveloped reserves	157,754	61,992	372,648	281,854
Total proved reserves	337,583	138,949	846,477	617,612

Proved reserves. Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Total extensions and discoveries of 34.2 MMBOE in 2018 were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased our proved reserves.

Purchases of minerals in place totaled 25.7 MMBOE during 2018 and were primarily attributable to the acquisition in the Williston Basin in July 2018 as further described in "Acquisitions and Divestitures" within Item 1 of this Annual Report on Form 10 K.

In 2018, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 110.7 MMBOE. Included in these revisions were 99.9 MMBOE of proved undeveloped reserves no longer expected to be developed within five years from their initial recognition. As a result of sustained lower crude oil prices in recent years, we have moved toward a more disciplined capital development program focused on the highest-return projects and the generation of free cash flow. This shift in strategy resulted in a change in the timing of our development plans related to our PUD reserves in certain areas. These revisions do not represent the elimination of recoverable hydrocarbons physically in place, however, as they may be developed in the future. In addition, there were 38.1 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance across our Northern and Central Rockies assets and 27.3 MMBOE of upward adjustments caused by higher crude oil, NGL and natural gas prices incorporated into our reserve estimates at December 31, 2018 as compared to December 31, 2017.

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Proved undeveloped reserves. Our PUD reserves decreased 45% or 127.5 MMBOE on a net basis from December 31, 2017 to December 31, 2018. The following table provides a reconciliation of our PUDs for the year ended December 31, 2018:

	Total (MBOE)
PUD balance—December 31, 2017	281,854
Converted to proved developed through drilling	(51,379)
Added from extensions and discoveries	14,946
Purchased	21,623
Revisions	(112,735)
PUD balance—December 31, 2018	154,309

During 2018, we incurred \$568 million in capital expenditures, or \$11.05 per BOE, to drill and bring on-line 51.4 MMBOE of PUD reserves. In addition, we added 14.9 MMBOE of PUDs from extensions and discoveries during the year primarily due to successful drilling in the Williston Basin. We have made an investment decision and adopted a development plan to drill all of our individual PUD locations within five years of the date such PUDs were added. In that regard, under our current 2019 development plan, we expect to convert approximately 38.6 MMBOE of PUDs to proved developed reserves during the year.

Preparation of reserves estimates. We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to our internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm Cawley, Gillespie & Associates, Inc. ("CG&A") meets with our technical personnel in our Denver office to review field performance and future development plans. Following this review, the reserve database and supporting data is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the reservoir engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. W. Todd Brooker, President. Mr. Brooker is a State of Texas Licensed Professional Engineer. Refer to Exhibit 99.2 of this Annual Report on Form 10 K for the Report of Cawley, Gillespie & Associates, Inc. and further information regarding the professional qualifications of Mr. Brooker.

Our Senior Vice President of Planning and Reservoir Engineering is responsible for overseeing the preparation of the reserves estimates. He has over 37 years of experience, including reservoir engineering and reserve estimation, and he holds a Bachelor of Science degree in petroleum engineering from the Colorado School of Mines. He is a registered Professional Engineer and a member of the Society of Petroleum Engineers.

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Acreage

The following table summarizes gross and net developed and undeveloped acreage by core area at December 31, 2018. Net acreage represents our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests has been excluded.

	Developed Acreage		Undeveloped Acreage (1)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Northern Rocky Mountains	742,593	440,227	43,172	30,216	785,765	470,443
Central Rocky Mountains	40,027	36,234	60,974	52,655	101,001	88,889
Other (2)	98,964	62,806	73,780	29,700	172,744	92,506
	881,584	539,267	177,926	112,571	1,059,510	651,838

(1) Out of a total of approximately 177,900 gross (112,600 net) undeveloped acres as of December 31, 2018, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 5% in 2019, 18% in 2020 and 12% in 2021.

(2) Other includes Arkansas, Colorado, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah and Wyoming.

Production History

The following table presents historical information about our produced oil and gas volumes:

	Year Ended December 31,		
	2018	2017	2016
Total company production			
Oil (MMBbl)	31.5	29.3	34.0
NGL (MMBbl)	7.4	7.0	6.6
Natural gas (Bcf)	46.8	41.3	41.4
Total (MMBOE)	46.7	43.1	47.5
Daily average (MBOE/d)	128.0	118.1	129.9
Sanish field production (1)			
Oil (MMBbl)	6.2	5.7	7.2
NGL (MMBbl)	1.2	1.1	1.0
Natural gas (Bcf)	7.2	7.1	7.8
Total (MMBOE)	8.6	8.0	9.5
Average sales prices (before the effects of hedging)			
Oil (per Bbl)	$ 58.70	$ 44.30	$ 34.36
NGLs (per Bbl)	$ 20.78	$ 16.00	$ 8.88
Natural gas (per Mcf)	$ 1.66	$ 1.78	$ 1.40
Average production costs (per BOE)			
Lease operating expenses	$ 6.68	$ 6.47	$ 6.59
Gathering, transportation, compression and other	$ 1.03	$ 2.10	$ 1.66

(1) The Sanish field was our only field that contained 15% or more of our total proved reserve volumes during the periods presented.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by core area at December 31, 2018. A net well represents our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

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The following table summarizes gross and net productive oil and natural gas wells by core area at December 31, 2018. A net well represents our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Northern Rocky Mountains	2,990	1,347	-	-	2,990	1,347
Central Rocky Mountains	394	314	-	-	394	314
Other (2)	1,544	396	68	40	1,612	436
Total	4,928	2,057	68	40	4,996	2,097

(1) 23 wells have multiple completions, and these 23 wells contain a total of 47 completions. One or more completions in the same bore hole are counted as one well.
(2) Other primarily includes non-core oil and gas properties located in Colorado, New Mexico, North Dakota, Texas and Wyoming.

Oil and Gas Drilling Activity

We are engaged in numerous drilling activities on properties presently owned, and we intend to drill or develop other properties acquired in the future. The following table sets forth our oil and gas drilling activity for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2018						
Development	210	-	210	120.9	-	120.9
Exploratory	1	-	1	0.8	-	0.8
Total	211	-	211	121.7	-	121.7
2017						
Development	238	-	238	164.1	-	164.1
Exploratory	-	-	-	-	-	-
Total	238	-	238	164.1	-	164.1
2016						
Development	89	-	89	48.2	-	48.2
Exploratory	-	-	-	-	-	-
Total	89	-	89	48.2	-	48.2

As of December 31, 2018, we had five operated drilling rigs active on our properties in our Northern Rocky Mountains area. As of December 31, 2018, we had 166 gross (67.6 net) operated and non-operated wells in the process of drilling, completing or waiting on completion.

Hydraulic Fracturing

Hydraulic fracturing is a common practice in the oil and gas industry that is used to stimulate production of hydrocarbons from tight oil and gas formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. This process has typically been regulated by state oil and gas commissions. However, as described in more detail in “Business – Regulation – Environmental Regulations – Hydraulic Fracturing” in Item 1 of this Annual Report on Form 10 K, the EPA has initiated the regulation of hydraulic fracturing, other federal agencies are examining hydraulic fracturing, and federal legislation is pending with respect to hydraulic fracturing. We have utilized hydraulic fracturing in the completion of our wells in our most active areas located in the states of North Dakota, Montana and Colorado and we plan to continue to utilize this completion methodology.

Substantially all of our 154.3 MMBOE of proved undeveloped reserves are associated with hydraulic fracture treatments.

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We are not aware of any environmental incidents, citations or suits that have occurred during the last three years related to hydraulic fracturing operations involving oil and gas properties that we operate or in which we own a non-operated interest.

In order to minimize any potential environmental impact from hydraulic fracture treatments, we have taken the following steps:

· we follow fracturing and flowback procedures that comply with or exceed North Dakota Industrial Commission or other state requirements;
· we train all company and contract personnel who are responsible for well preparation, fracture stimulation and flowback on our procedures;
· we have implemented the incremental procedures of running a well casing caliper, visually inspecting the surface joint of intermediate casing and, if a lighter wall joint of casing or drilling wear is detected, reducing the minimum burst pressure accordingly;
· for wells that are within one mile of major bodies of water or locations that lead to bodies of water, we construct berming around the well location prior to initiating fracturing operations;
· we run fracturing strings in certain situations when extra precaution is warranted, such as where the anticipated maximum treating pressure for the well is greater than the pressure rating of the intermediate casing or in areas located within one mile of major bodies of water;
· we conduct annual emergency incident response drills in our active areas; and
· we are a member of the Sakakawea Area Spill Response LLC (“SASR”), which is comprised of 17 oil and gas related companies operating in the Missouri River and Lake Sakakawea regions of North Dakota. Members agreed to share spill response resources and maintain SASR-owned water response equipment that can be accessed quickly in the early stages of a spill.

While we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations, we do have general liability and excess liability insurance policies that we believe would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry, generally provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

As of December 31, 2018, we had two physical delivery contracts which require us to deliver fixed volumes of crude oil. One of these contracts is tied to oil production at our Sanish field in Mountrail County, North Dakota and became effective upon completion of the Dakota Access Pipeline on June 1, 2017. The other contract is tied to oil production at our Redtail field in Weld County, Colorado. The following table summarizes our Sanish and Redtail delivery commitments as of December 31, 2018:

Period	Sanish Contracted Crude Oil Volumes (Bbl)	Redtail Contracted Crude Oil Volumes (Bbl)	As a Percentage of Total 2018 Oil Production
Jan - Dec 2019	5,475,000	15,975,000	68%
Jan - Dec 2020	5,490,000	4,140,000	31%
Jan - Dec 2021	5,475,000	—	17%
Jan - Dec 2022	5,475,000	—	17%
Jan - Dec 2023	5,475,000	—	17%

Jan - Dec 2024	2,280,000	—	7%

Under the terms of the Sanish contract, if we fail to deliver the committed volumes we will be required to pay a deficiency payment of $7.00 per undelivered Bbl, subject to upward adjustment, over the duration of the contract. However, we believe that our production

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and reserves are sufficient to fulfill the delivery commitment at our Sanish field, and we therefore expect to avoid any payments for deficiencies under this contract.

Under the terms of the Redtail contract, if we fail to deliver the committed volumes we are required to pay a deficiency payment that currently totals $5.08 per undelivered Bbl (subject to upward adjustment) over the duration of the contract. We have determined that it is not probable that future oil production from our Redtail field will be sufficient to meet the minimum volume requirements specified in the related physical delivery contract, and as a result, we expect to make periodic deficiency payments for any shortfalls in delivering the minimum committed volumes. We recognize any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred. During 2018, 2017 and 2016, total deficiency payments under this contract, as well as a second Redtail contract that we terminated in February 2018, amounted to $39 million, $66 million and $43 million, respectively. In conjunction with the termination of the previous Redtail contract in February 2018, we paid $61 million to the counterparty to settle all future minimum volume commitments under that agreement.

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Item 3. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is management's opinion that the loss for any litigation matters and claims we are involved in that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 20, 2019, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
Bradley J. Holly	48	Chairman, President and Chief Executive Officer
Charles J. Rimer	61	Chief Operating Officer
Michael J. Stevens	53	Senior Vice President and Chief Financial Officer
Timothy M. Sulser	42	Chief Corporate Development and Strategy Officer
Bruce R. DeBoer	66	Senior Vice President, General Counsel and Corporate Secretary
Peter W. Hagist	58	Senior Vice President, Planning and Reservoir Engineering
Heather M. Duncan	48	Vice President, Human Resources
Sirikka R. Lohoefener	40	Vice President, Controller and Treasurer

The following biographies describe the business experience of our executive officers:

Bradley J. Holly joined us in November 2017 upon his appointment as director and election as President and Chief Executive Officer. Mr. Holly was appointed Chairman of the Board in May 2018. Mr. Holly has 24 years of experience in the oil and gas industry. Prior to joining Whiting, he held various management and technical positions during his 20 years at Anadarko Petroleum Corporation including Executive Vice President, U.S. Onshore Exploration and Production; Senior Vice President, U.S. Onshore Exploration and Production; Senior Vice President, Operations; Vice President, Operations for the Southern and Appalachia Region; among others. He began his career in 1994 with Amoco Corporation. Mr. Holly holds a Bachelor of Science degree in petroleum engineering from Texas Tech University, and he is a graduate of the Harvard Business School's Advanced Management Program.

Charles J. Rimer joined us in November 2018 as Chief Operating Officer. Mr. Rimer has 36 years of experience in the industry. Prior to joining Whiting, he held various management and technical positions during his 16 years at Noble Energy, Inc. including Senior Vice President, Global Services; Senior Vice President, U.S. Onshore; Senior Vice President, Global EHSR and Operations Services; Vice President of Operations Services; among others. He also held various management and technical positions at Aspect Resources, Vastar Resources and ARCO Oil & Gas Company where he began his career in 1983. Mr. Rimer holds a Bachelor of Arts degree in business from Furman University and Bachelor of Science degree in petroleum engineering from the University of Texas.

Michael J. Stevens joined us in May 2001 as Controller, became Treasurer in January 2002 and became Vice President and Chief Financial Officer in March 2005. Mr. Stevens was elected Senior Vice President and Chief Financial Officer effective March 1, 2015. His 32 years of oil and gas experience includes eight years of service in various positions including Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a Certified Public Accountant.

Timothy M. Sulser joined us in September 2018 as Chief Corporate Development and Strategy Officer. Mr. Sulser has 20 years of oil and gas experience. He co-founded Salt Creek Oil and Gas, LLC in 2015 after five years as an investment banker with Tudor, Pickering, Holt & Co. ("TPH"), most recently heading its Denver office. While at TPH, Mr. Sulser advised upstream clients on acquisitions and divestitures and energy capital markets. Prior to joining TPH, he worked as a reservoir engineer for reserve engineering consultant Netherland, Sewell, and Associates in Houston, Texas. He started his career with Marathon Oil Company in Lafayette, Louisiana. Mr. Sulser holds a Bachelor of Science degree in petroleum engineering from Montana Tech and a Master of Science degree in operations research from Columbia University.

Bruce R. DeBoer joined us as Vice President, General Counsel and Corporate Secretary in January 2005 and was elected Senior Vice President, General Counsel and Corporate Secretary effective January 2018. Previously, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has 39 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science degree in political science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

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Peter W. Hagist joined us in October 2005 as Vice President, Operations-Midland. He was elected Senior Vice President of Planning in June 2014 and Senior Vice President of Planning and Reservoir Engineering in July 2018. Mr. Hagist has 37 years of experience in the oil and gas industry and 28 years of experience managing tertiary recovery operations. Prior to joining Whiting, he held management and professional positions with Kinder Morgan CO2 Company and Pennzoil Exploration and Production Company. Mr. Hagist holds a Bachelor of Science degree in petroleum engineering from the Colorado School of Mines. He is a registered Professional Engineer and a member of the Society of Petroleum Engineers.

Heather M. Duncan joined us in February 2002 as Assistant Director of Human Resources and in January 2003 became Director of Human Resources. In January 2008, she was appointed Vice President of Human Resources. Ms. Duncan has 22 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts degree in anthropology and an MBA degree from the University of Colorado. She is a certified Senior Professional in Human Resources.

Sirikka R. Lohoefener joined us in June 2006 as a Senior Financial Accountant, became Financial Reporting Manager in January 2011 and Controller in March 2015. She was appointed Controller and Treasurer in March 2017 and Vice President, Controller and Treasurer in December 2018 and serves as the Company’s designated principal accounting officer. Prior to joining Whiting, Ms. Lohoefener spent five years with Wagner, Burke & Barnes, LLP, a public accounting firm previously based in Golden, Colorado. She holds a Master of Accountancy degree from the University of Missouri and is a Certified Public Accountant.

Executive officers are elected by, and serve at the discretion of, the Board of Directors. There are no family relationships between any of our directors or executive officers.

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PART II

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

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL". On February 20, 2019, there were 607 holders of record of our common stock.

On November 8, 2017, our Board of Directors approved a reverse stock split of our common stock at a ratio of one-for-four and a reduction in the number of authorized shares of our common stock from 600,000,000 shares to 225,000,000. Our common stock began trading on a split-adjusted basis on November 9, 2017 upon opening of the markets. All share and per share amounts in this Annual Report on Form 10 K for periods prior to November 2017 have been retroactively adjusted to reflect the reverse stock split.

We have not paid any cash dividends on our common stock since we were incorporated in July 2003, and we do not anticipate paying any such dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10 K.

The following information in this Item 5 of this Annual Report on Form 10 K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since December 31, 2013 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Exploration & Production Index. Such changes have been measured by dividing (a) the sum of (i) the cumulative amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2013 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones U.S. Exploration & Production Index, respectively.

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	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
Whiting Petroleum Corporation	$ 100	$ 53	$ 15	$ 19	$ 11	$ 9
Standard & Poor's Composite 500 Index	100	111	111	121	145	136
Dow Jones U.S. Exploration & Production Index	100	88	66	81	80	65

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Item 6. Selected Financial Data

The consolidated statements of operations and statements of cash flows information for the years ended December 31, 2018, 2017 and 2016 and the consolidated balance sheet information at December 31, 2018 and 2017 are derived from our audited financial statements included elsewhere in this report. The consolidated statements of operations and statements of cash flows information for the years ended December 31, 2015 and 2014 and the consolidated balance sheet information at December 31, 2016, 2015 and 2014 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent proved property acquisitions beginning on the following closing dates: properties in North Dakota and Montana, July 31, 2018, and properties related to the acquisition of Kodiak Oil & Gas Corp., December 8, 2014. In addition, our historical results also include the effects of our recent property divestitures beginning on the following closing dates: properties in the Fort Berthold Indian Reservation area, September 1, 2017; gas processing plants and related gathering systems in North Dakota, January 1, 2017; properties in the North Ward Estes field, July 27, 2016; water facilities in Colorado, December 16, 2015; non-core properties in various fields across multiple states, December 15, 2015, November 12, 2015 and June 10, 2015; and the underlying properties of Whiting USA Trust I, April 15, 2015. For a discussion of other material factors affecting the comparability of the information presented below, refer to “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this Annual Report on Form 10 K.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions, except per share data)				
Consolidated Statements of Operations Information					
Operating revenues	$ 2,081.4	$ 1,481.4	$ 1,285.0	$ 2,092.5	$ 3,024.6
Net income (loss) attributable to common shareholders	$ 342.5	$ (1,237.6)	$ (1,339.1)	$ (2,219.2)	$ 64.8
Earnings (loss) per common share, basic (1)	$ 3.77	$ (13.65)	$ (21.27)	$ (45.41)	$ 2.12
Earnings (loss) per common share, diluted (1)	$ 3.73	$ (13.65)	$ (21.27)	$ (45.41)	$ 2.12
Other Financial Information					
Net cash provided by operating activities	$ 1,092.0	$ 577.1	$ 595.0	$ 1,051.4	$ 1,815.3
Net cash provided by (used in) investing activities	$ (953.1)	$ 73.4	$ (222.6)	$ (1,982.1)	$ (2,860.5)
Net cash provided by (used in) financing activities	$ (1,004.7)	$ 155.6	$ (315.3)	$ 868.7	$ 423.9
Cash capital expenditures	$ 956.7	$ 852.0	$ 543.9	$ 2,483.7	$ 2,888.4
Consolidated Balance Sheet Information					
Total assets	$ 7,759.6	$ 8,403.0	$ 9,876.1	$ 11,389.1	$ 13,993.1
Long-term debt	$ 2,792.3	$ 2,764.7	$ 3,535.3	$ 5,197.7	$ 5,602.4
Total equity (2)	$ 4,270.3	$ 3,919.1	$ 5,149.2	$ 4,758.6	$ 5,703.0

(1) On November 8, 2017, our Board of Directors approved a one-for-four reverse stock split of our common stock. Earnings (loss) per common share for periods prior to 2017 have been retroactively adjusted to reflect the reverse stock split.

(2) No cash dividends were declared or paid on our common stock during the periods presented.

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

Unless the context otherwise requires, the terms "Whiting", "we", "us", "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties, such as the acquisition discussed below under "Acquisition and Divestiture Highlights," and exploring other basins where we can apply our existing knowledge and expertise to build production and add proved reserves. As a result of lower crude oil prices during 2016 and 2017, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2018, we continued to focus on high-return projects in our asset portfolio that added production and reserves while generating free cash flows from operations. In 2019, we expect to continue to closely align our capital spending with cash flows generated from operations while focusing on developing our large resource play in the Williston Basin of North Dakota and Montana. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under "Acquisition and Divestiture Highlights" and in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, competition from other sources of energy, and the other items discussed under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10 K. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2017:

	2017				2018			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude oil	$ 51.86	$ 48.29	$ 48.19	$ 55.39	$ 62.89	$ 67.90	$ 69.50	$ 58.83
Natural gas	$ 3.07	$ 3.09	$ 2.89	$ 2.87	$ 3.13	$ 2.77	$ 2.88	$ 3.62

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserve quantities. Substantial and extended declines in oil, NGL and natural gas prices have resulted, and may result, in impairments of our proved oil and gas properties or undeveloped acreage (such as the impairments discussed below under "Results of Operations") and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders.

Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement. Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives.

For a discussion of material changes to our proved reserves from December 31, 2017 to December 31, 2018 and our ability to convert PUDs to proved developed reserves, refer to "Reserves" in Item 2 of this Annual Report on Form 10 K. Additionally, for a discussion relating to the minimum remaining terms of our leases, refer to "Acreage" in Item 2 of this Annual Report on Form 10 K.

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2018 Highlights and Future Considerations

Operational Highlights

Northern Rocky Mountains – Williston Basin

Our properties in the Williston Basin of North Dakota and Montana target the Bakken and Three Forks formations. Net production from the Williston Basin averaged 111.5 MBOE/d for the fourth quarter of 2018, representing a 4% increase from 106.9 MBOE/d in the third quarter of 2018. Production from this area in the fourth quarter was negatively impacted by extended downtime at a third-party gas processing facility and gas curtailments resulting from takeaway capacity issues. The gas plant was returned to service late in the fourth quarter, and the curtailments have been lifted during the first part of 2019. Across our acreage in the Williston Basin, we have implemented customized, right-sized completion designs which utilize the optimum volume of proppant, fluids, and frac stages to increase well performance while reducing cost. We plan to continue to use right-sized completion designs on wells we drill in 2019, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and 3-D bit cutter technology to reduce time-on-location and total well cost. As of December 31, 2018, we had five rigs active in the Williston Basin. We drilled 36 wells and put 41 operated wells on production in this area during the fourth quarter of 2018.

Central Rocky Mountains – Denver-Julesburg Basin

Our Redtail field in the Denver-Julesburg Basin (“DJ Basin”) in Weld County, Colorado targets the Niobrara and Codell/Fort Hays formations. Net production from the Redtail field averaged 17.8 MBOE/d in the fourth quarter of 2018, representing a 16% decrease from 21.2 MBOE/d in the third quarter of 2018. We have established production in the Niobrara “A”, “B” and “C” zones and the Codell/Fort Hays formations. During 2017, we completed and brought on production a significant portion of our drilled uncompleted well inventory (“DUCs”) from yearend 2016. In late 2017, based on the comparative well performance results of the DJ Basin to the Williston Basin, our management decided to concentrate development activities during 2018 in the Williston Basin. We completed 22 DUCs in our Redtail field during the first half of 2018 and have since ceased additional development activity in this area until commodity prices further recover.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of December 31, 2018, the plant was processing 30 MMcf/d.

Financing Highlights

On January 26, 2018, we paid $1.0 billion to redeem all of the then outstanding $961 million aggregate principal amount of our 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with proceeds from the issuance of our 2026 Senior Notes and borrowings under our credit agreement. Refer to the “Long-Term Debt” footnote in the notes to the consolidated financial statements for more information on this financing transaction.

2019 Exploration and Development Budget

Our 2019 exploration and development (“E&D”) budget is a range of $800 million to $840 million, which we expect to fund substantially with net cash provided by our operating activities and cash on hand. The forecasted midpoint of the 2019 E&D budget of $820 million represents a slight decrease from the $832 million incurred on E&D expenditures during 2018. This reduced spending is primarily attributable to our Redtail field where we incurred $83 million in drilling and development costs during 2018, but where we have not allocated any of our 2019 E&D budget due to well performance results in this area compared to the Williston Basin. Offsetting this decreased spending at our Redtail field is an increase of $62 million of planned drilling and development costs in the Northern Rocky Mountains. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate, adjust our E&D budget, enter into agreements with industry partners, divest certain oil and gas property interests, adjust borrowings outstanding under our credit facility or access the capital markets as necessary. The midpoint of our 2019 E&D budget currently is allocated among our major development areas as indicated in the table below. Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital.

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Development Area	2019 Exploration and Development Budget (in millions)
Northern Rocky Mountains	$ 662
Non-operated properties	40
Land	30
Other (1)	88
Total	$ 820

(1) Comprised of facilities and exploration costs.

Acquisition and Divestiture Highlights

On July 31, 2018, we completed the acquisition of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The producing properties had estimated proved reserves of 25.7 MMBOE as of the acquisition date, 84% of which were crude oil and NGLs.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31, 2018	2017	2016
Net production			
Oil (MMBbl)	31.5	29.3	34.0
NGLs (MMBbl)	7.4	7.0	6.6
Natural gas (Bcf)	46.8	41.3	41.4
Total production (MMBOE)	46.7	43.1	47.5
Net sales (in millions)			
Oil (1)	$ 1,850.1	$ 1,296.4	$ 1,167.8
NGLs	153.6	111.6	59.0
Natural gas	77.7	73.4	58.2
Total oil, NGL and natural gas sales	$ 2,081.4	$ 1,481.4	$ 1,285.0
Average sales prices			
Oil (per Bbl) (1)	$ 58.70	$ 44.30	$ 34.36
Effect of oil hedges on average price (per Bbl)	(4.98)	0.29	4.46
Oil net of hedging (per Bbl)	$ 53.72	$ 44.59	$ 38.82
Weighted average NYMEX price (per Bbl) (2)	$ 64.69	$ 51.11	$ 42.71
NGLs (per Bbl)	$ 20.78	$ 16.00	$ 8.88
Natural gas (per Mcf)	$ 1.66	$ 1.78	$ 1.40
Weighted average NYMEX price (per MMBtu) (2)	$ 3.11	$ 2.97	$ 2.47
Costs and expenses (per BOE)			
Lease operating expenses	$ 6.68	$ 6.47	$ 6.59
Gathering, transportation, compression and other	$ 1.03	$ 2.10	$ 1.66
Production and ad valorem taxes	$ 3.68	$ 2.80	$ 2.35

Depreciation, depletion and amortization	$ 16.73	$ 22.01	$ 24.64
General and administrative	$ 2.64	$ 2.88	$ 3.09

(1) Before consideration of hedging transactions.
(2) Average NYMEX pricing weighted for monthly production volumes.

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Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $600 million to $2.1 billion when comparing 2018 to 2017. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil, NGL and gas volumes increased 8%, 6% and 13%, respectively, between periods. The oil volume increase between periods was primarily attributable to new wells drilled and completed in the Williston Basin and DJ Basin which added 8,475 MBbl and 2,700 MBbl, respectively, of oil production during 2018 compared to 2017. These increases were partially offset by normal field production decline across several of our areas, as well as 2017 oil and gas property divestitures which negatively impacted oil production in 2018 by 1,835 MBbl. The NGL volume increase between periods generally relates to new wells drilled and completed in the Williston Basin and DJ Basin over the last twelve months, as well as additional volumes processed as more wells were connected to gas processing plants in the Williston Basin in an effort to increase our overall gas capture rate in this area and reduce flared volumes. Many of the new Williston Basin wells are in areas with higher gas-to-oil production ratios than previously drilled areas. These NGL volume increases were partially offset by normal field production decline, the impact of extended downtime at a third-party gas processing facility during the second half of 2018 and gas curtailments resulting from takeaway capacity issues in the fourth quarter of 2018. The gas volume increase between periods was primarily due to new wells drilled and completed at our Williston Basin and DJ Basin properties which resulted in 11,070 MMcf and 5,045 MMcf, respectively, of additional gas volumes during 2018 as compared to 2017. These increases were partially offset by normal field production decline, the impact of the gas processing facility downtime and gas curtailments discussed above, as well as 2017 property divestitures which negatively impacted gas production in 2018 by 340 MMcf.

In addition to the above production-related increases in net revenue, there were also increases in the average sales price realized for oil and NGLs in 2018 compared to 2017. Our average price for oil (before the effects of hedging) and NGLs increased 33% and 30%, respectively, while our average price for natural gas decreased 7% between periods. Our average sales price realized for oil is impacted by deficiency payments we were making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During 2018 and 2017, our total average sales price realized for oil was $1.25 per Bbl lower and $2.27 per Bbl lower, respectively, as a result of these deficiency payments. On February 1, 2018, we paid $61 million to the counterparty to one of these Redtail delivery contracts to settle all future minimum volume commitments under the agreement. The remaining agreement will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contract terminates. Refer to the “Commitments and Contingencies” footnote in the notes to consolidated financial statements for more information on these physical delivery contracts and the related deficiency payments. Our average sales price for oil was further impacted by the adoption of FASB ASC Topic 606 – Revenue from Contracts with Customers (“ASC 606”), which resulted in an increase of $0.49 per Bbl for 2018. In addition, the adoption of ASC 606 negatively impacted our average sales price for NGLs and natural gas by $3.30 per Bbl and $0.69 per Mcf, respectively, for 2018. Refer to the “Revenue Recognition” footnote in the consolidated financial statements for more information on the impact of this new standard.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2018 were $312 million, a $33 million increase over 2017. This increase was primarily due to new wells put on production in the Williston Basin and the DJ Basin during 2018, partially offset by the elimination of $18 million of LOE attributable to properties that we divested during 2017.

Our lease operating expenses on a BOE basis also increased when comparing 2018 to 2017. LOE per BOE amounted to $6.68 during 2018, which represents an increase of $0.21 per BOE (or 3%) from 2017. This increase was mainly due to the overall increase in LOE expense discussed above.

Gathering, Transportation, Compression and Other. Our gathering, transportation, compression and other expenses ("GTC") during 2018 were $48 million, a $42 million decrease over 2017. This decrease was primarily due to the impact of adopting ASC 606 effective January 1, 2018, which reduced GTC by $41 million for 2018, and the elimination of $7 million of GTC attributable to properties that we divested during 2017. Refer to the "Revenue Recognition" footnote in the consolidated financial statements for more information on the impact of ASC 606.

GTC on a BOE basis also decreased when comparing 2018 to 2017. GTC per BOE amounted to $1.03 during 2018, which represents a decrease of $1.07 per BOE (or 51%) from 2017. This decrease was mainly due to the impact of the adoption of ASC 606 and property divestitures as discussed above.

Production and Ad Valorem Taxes. Our production and ad valorem taxes increased $51 million in 2018 as compared to 2017. This increase was primarily related to $39 million of higher production taxes during 2018 as compared to 2017 due to higher oil, NGL and natural gas sales revenue between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 7.8% and 8.3% for 2018 and 2017, respectively. Our production tax rate for 2018 was less than the rate for 2017 due to (i) successful well completions during the second half of 2017 and early 2018 in Colorado, which has a 5% tax rate, (ii) certain North Dakota wells receiving stripper well status, which also has a 5% tax rate, and (iii) severance tax refunds received during 2018.

Ad valorem taxes also increased $12 million during 2018 as compared to 2017 primarily due to new wells completed in Colorado during the second half of 2017 and early 2018.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $168 million in 2018 as compared to 2017. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2018	2017
Depletion	$ 763,429	$ 927,594
Accretion of asset retirement obligations	11,405	13,809
Depreciation	6,495	7,536
Total	$ 781,329	$ 948,939

DD&A decreased between periods primarily due to $164 million in lower depletion expense, consisting of a $223 million decrease related to a lower depletion rate between periods, partially offset by a $59 million increase due to higher overall production volumes during 2018. On a BOE basis, our overall DD&A rate of $16.73 for 2018 was 24% lower than the rate of $22.01 in 2017. The primary factors contributing to this lower DD&A rate were impairment write-downs on proved oil and gas properties recognized in the fourth quarter of 2017.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $869 million in 2018 as compared to 2017. The components of our exploration and impairment expense were as follows (in thousands):

	Year Ended December 31,	
	2018	2017
Impairment	$ 45,288	$ 899,853
Exploration	22,080	36,324
Total	$ 67,368	$ 936,177

Impairment expense in 2018 primarily related to (i) $29 million of leasehold amortization costs associated with individually insignificant unproved properties and (ii) $8 million in impairment write-downs of undeveloped acreage costs for leases where we have no future plans to drill. Impairment expense in 2017 primarily related to (i) $835 million in non-cash impairment charges for the partial write-down of our Redtail field in Colorado due to a reduction of reserves driven by well performance results in this area, (ii) $47 million of leasehold amortization associated with individually insignificant unproved properties, and (iii) $12 million in impairment write-downs of undeveloped acreage costs for leases where we have no future plans to drill.

Exploration costs decreased $14 million between periods primarily due to the 2017 write-off of $12 million of pre-drilling expenditures for well locations in our Redtail field, as well as a decrease in geology-related general and administrative expenses, partially offset by increased deficiency fees paid under our produced water disposal agreement at our Redtail field.

General and Administrative Expenses. We report general and administrative ("G&A") expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Year Ended December 31,	
	2018	2017
General and administrative expenses	$ 220,100	$ 228,669
Reimbursements and allocations	(96,850)	(104,381)
General and administrative expenses, net	$ 123,250	$ 124,288

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G&A expense before reimbursements and allocations decreased $9 million during 2018 as compared to 2017 primarily due to lower bad debt expense related to the collection of certain receivables that had been previously deemed uncollectible. This decrease was offset by a decrease in reimbursements and allocations resulting from a lower number of field workers on Whiting-operated properties in 2018 compared to 2017.

Our G&A expenses on a BOE basis also decreased between periods. G&A expense per BOE amounted to $2.64 in 2018, which represents a decrease of $0.24 per BOE (or 8%) from 2017. This decrease was mainly due to higher overall production volumes between periods.

Derivative (Gain) Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative (gain) loss, net amounted to a loss of $17 million for 2018, which consisted of a $19 million loss on our costless collar and swap commodity derivative contracts resulting from the upward shift in the futures curve of forecasted commodity prices ("forward price curve") for crude oil from January 1, 2018 (or the 2018 date on which new contracts were entered into) to December 31, 2018, partially offset by a $2 million fair value gain on our long-term crude oil sales and delivery contract. Derivative (gain) loss, net for 2017 amounted to a loss of $123 million, which consisted of a $54 million fair value loss on our long-term crude oil sales and delivery contract, a $50 million loss on our costless collar commodity derivative contracts resulting from the more significant upward shift in the same forward price curve from January 1, 2017 (or the 2017 date on which prior year contracts were entered into) to December 31, 2017, and a $19 million fair value loss on embedded derivatives.

Refer to Item 7A, "Quantitative and Qualitative Disclosures about Market Risk", for a list of our outstanding commodity derivative contracts as of February 20, 2019.

Loss on Sale of Properties. During 2017, we sold our interests in the Fort Berthold Indian Reservation Area of North Dakota (the "FBIR Assets") for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. Refer to the "Acquisitions and Divestitures" footnote in the consolidated financial statements for more information on this transaction. There were no other property divestitures resulting in a significant gain or loss on sale during 2018 or 2017.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Year Ended December 31,	
	2018	2017
Notes	$ 152,366	$ 133,123
Amortization of debt issue costs, discounts and premiums	30,700	31,715
Credit agreement	13,262	24,971
Other	1,146	1,279
Total	$ 197,474	$ 191,088

The increase in interest expense of $6 million between periods was mainly attributable to higher interest incurred on our notes in 2018 compared to 2017. The $19 million increase in note interest was primarily due to $66 million of interest incurred on the 2026 Senior Notes issued in December 2017, partially offset by a $45 million reduction in interest related to the redemption of the 2019 Notes in January 2018. Refer to the "Long-Term Debt" footnote in the notes to consolidated financial statements for more information on these debt transactions. The increase in note interest was partially offset by a $12 million decrease in interest incurred on the credit agreement between periods due to a lower average outstanding balance. Our weighted average borrowings outstanding during 2018 were $117 million compared to $420 million during 2017.

Our weighted average debt outstanding during 2018 was $3.0 billion versus $3.3 billion for 2017. Our weighted average effective cash interest rate was 5.5% during 2018 compared to 4.8% during 2017.

Loss on Extinguishment of Debt. During 2018, we redeemed all of the remaining $961 million aggregate principal amount of 2019 Senior Notes and recognized a $31 million loss on extinguishment of debt. During 2017, we redeemed all of the remaining $275 million aggregate principal amount of 2018 Senior Subordinated Notes and recognized a $2 million loss on extinguishment of debt. Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for more information on these debt transactions.

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Income Tax Expense (Benefit). Income tax expense for 2018 totaled $1 million as compared to a benefit of $483 million for 2017. The $483 million benefit in 2017 was primarily related to a pre-tax loss of $1.7 billion as well as $42 million of additional tax benefits resulting from a reduction in the U.S. federal statutory tax rate upon enactment of the Tax Cuts and Jobs Act (the "TCJA") in December 2017. These tax benefits were partially offset by the tax impact of the $835 million impairment charge at our Redtail field and the establishment of a full valuation allowance against our net deferred tax assets as of December 31, 2017. As a result of our positive pre-tax income in 2018, we transitioned from a net deferred tax asset position to a net deferred tax liability position as of December 31, 2018. Accordingly, we released the valuation allowance related to our general net deferred tax assets that was established in 2017.

Our effective tax rates for 2018 and 2017 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes, permanent taxable differences and changes in the valuation allowance. Our overall effective tax rate decreased from 28.1% for 2017 to 0.4% for 2018 primarily due to the release of the valuation allowance related to our general net deferred tax assets in 2018 and the reduction of the corporate tax rate to 21% as a result of the TCJA.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $196 million to $1.5 billion when comparing 2017 to 2016. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes decreased 14%, while our NGL volumes increased 5% and our natural gas sales volumes remained relatively consistent between periods. The oil volume decrease between periods was primarily attributable to normal field production decline across all of our areas resulting from reduced drilling and completion activity during 2016 and 2017 in response to the depressed commodity price environment. In addition, we completed certain oil and gas property divestitures during 2016 and 2017, which negatively impacted oil production in 2017 by 2,330 MBbl. These decreases were partially offset by new wells drilled and completed in the Williston Basin and DJ Basin which added 6,040 MBbl and 1,750 MBbl, respectively, of oil production during 2017 as compared to 2016. The NGL volume increase between periods generally relates to new wells drilled and completed in the Williston Basin and DJ Basin over the twelve months ended December 31, 2017, as well as additional volumes processed as more wells were connected to gas processing plants in the Williston Basin in an effort to increase our overall gas capture rate in this area and reduce flared volumes. Many of the new Williston Basin wells are in areas with higher gas-to-oil production ratios than previously drilled areas. These NGL volume increases were partially offset by normal field production decline across all our areas. New wells drilled and completed at our Williston Basin and DJ Basin properties resulted in 8,555 MMcf and 910 MMcf, respectively, of additional gas volumes during 2017 as compared to 2016. This gas volume increase was entirely offset by normal field production decline across all of our areas and the 2016 and 2017 property divestitures, which negatively impacted gas production in 2017 by 690 MMcf.

These overall production-related decreases in net revenue were offset by increases in the average sales price realized for oil, NGLs and natural gas in 2017 compared to 2016. Our average price for oil (before the effects of hedging), NGLs and natural gas increased 29%, 80% and 27%, respectively, between periods. Our average sales price realized for oil was impacted by deficiency payments we were making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During 2017 and 2016, our total average sales price realized for oil was $2.27 per Bbl lower and $1.27 per Bbl lower, respectively, as a result of these deficiency payments.

Lease Operating Expenses. Our LOE during 2017 were $279 million, a $34 million decrease compared to 2016. This decrease was primarily due to a decline in the costs of oilfield goods and services resulting from cost reduction measures we have implemented and the elimination of LOE attributable to properties that we divested during 2016 and 2017, as well as the general downturn in the oil and gas industry.

Our lease operating expenses on a BOE basis also decreased when comparing 2017 to 2016. LOE per BOE amounted to $6.47 during 2017, which represents a decrease of $0.12 per BOE (or 2%) from 2016. This decrease was mainly due to the overall decrease in LOE discussed above, partially offset by lower overall production volumes between periods.

Gathering, Transportation, Compression and Other. GTC during 2017 was $91 million, a $12 million increase over 2016. This increase was primarily due to higher production volumes between periods, as well as higher gas processing and oil gathering fees. This increase was partially offset by $12 million of GTC attributable to properties that we divested during 2016 and 2017.

GTC on a BOE basis also increased when comparing 2017 to 2016. GTC per BOE amounted to $2.10 during 2017, which represents an increase of $0.44 per BOE (or 27%) from 2016. This increase was mainly due to the overall increase in GTC discussed above.

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Production and Ad Valorem Taxes. Our production and ad valorem taxes increased $9 million in 2017 as compared to 2016. This increase was related to $15 million of higher production taxes between periods due to higher oil, NGL and natural gas sales. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis remained relatively consistent at 8.3% and 8.5% for 2017 and 2016, respectively.

Ad valorem taxes decreased $6 million during 2017 as compared to 2016 primarily due to the sale of our interests in the Robinson Lake and Belfield gas processing plants and the associated natural gas, crude oil and water gathering systems effective January 1, 2017 and the sale of our interests in our enhanced oil recovery project in the North Ward Estes field and certain CO_2 properties in the McElmo Dome field in July 2016.

Depreciation, Depletion and Amortization. Our DD&A expense decreased $223 million in 2017 as compared to 2016. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2017	2016
Depletion	$ 927,594	$ 1,149,302
Accretion of asset retirement obligations	13,809	13,801
Depreciation	7,536	8,479
Total	$ 948,939	$ 1,171,582

DD&A decreased between periods primarily due to $222 million in lower depletion expense, consisting of a $127 million decrease related to a lower depletion rate between periods and a $95 million decrease due to lower overall production volumes during 2017. On a BOE basis, our overall DD&A rate of $22.01 for 2017 was 11% lower than the rate of $24.64 in 2016. The primary factors contributing to this lower DD&A rate were (i) an increase to proved and proved developed reserves during the twelve months ended December 31, 2017 (excluding the effect of divestitures) mainly due to higher average oil and natural gas prices used to calculate our reserves, as well as upward performance revisions, extensions and discoveries in our Williston Basin area, and (ii) the impact of property divestitures.

Exploration and Impairment Costs. Our exploration and impairment costs increased $815 million in 2017 as compared to 2016. The components of our exploration and impairment expense were as follows (in thousands):

	Year Ended December 31,	
	2017	2016
Impairment	$ 899,853	$ 75,622
Exploration	36,324	45,846
Total	$ 936,177	$ 121,468

Impairment expense in 2017 primarily related to (i) $835 million in non-cash impairment charges for the partial write-down of our Redtail field in Colorado due to a reduction of reserves driven by well performance results in this area, (ii) $47 million of leasehold amortization associated with individually insignificant unproved properties, and (iii) $12 million in impairment write-downs of undeveloped acreage costs for leases where we have no future plans to drill. Impairment expense in 2016 primarily related to $60 million of leasehold amortization associated with individually insignificant unproved properties and $13 million in impairment write-downs of undeveloped acreage costs for leases where we have no future plans to drill.

Exploration costs decreased $10 million during 2017 as compared to 2016 primarily due to $18 million of lower rig termination fees incurred between periods, partially offset by the write-off of $12 million during 2017 of pre-drilling expenditures for well locations in our Redtail field where we have no future plans to drill.

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General and Administrative Expenses. We report G&A expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Year Ended December 31,	
	2017	2016
General and administrative expenses	$ 228,669	$ 264,948
Reimbursements and allocations	(104,381)	(118,070)
General and administrative expenses, net	$ 124,288	$ 146,878

G&A expense before reimbursements and allocations decreased $36 million during 2017 as compared to 2016 primarily due to lower employee compensation. Employee compensation decreased $39 million in 2017 as compared to 2016 primarily due to reductions in personnel during the twelve months ended December 31, 2017. The decrease in reimbursements and allocations for 2017 was primarily the result of property divestitures during the twelve months ended December 31, 2017.

Our general and administrative expenses on a BOE basis also decreased when comparing 2017 to 2016. G&A expense per BOE amounted to $2.88 during 2017, which represented a decrease of $0.21 per BOE (or 7%) from 2016. This decrease was mainly due to lower employee compensation, partially offset by lower overall production volumes between periods.

Derivative (Gain) Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative (gain) loss, net amounted to a loss of $123 million for 2017, which consisted of a $54 million fair value loss on our long-term crude oil sales and delivery contract, a $50 million loss on our costless collar commodity derivative contracts resulting from the upward shift in the forward price curve for crude oil from January 1, 2017 (or the 2017 date on which new contracts were entered into) to December 31, 2017, and a $19 million fair value loss on embedded derivatives. Derivative (gain) loss, net for 2016 amounted to a gain of $1 million, which consisted of a $59 million fair value gain on embedded derivatives, partially offset by a $58 million loss on commodity derivative contracts resulting from a more significant upward shift in the same forward price curve from January 1, 2016 (or the 2016 date on which prior year contracts were entered into) to December 31, 2016.

Loss on Sale of Properties. During 2017, we sold our interests in the FBIR Assets for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. During 2016, we sold our interests in the North Ward Estes and McElmo Dome properties for net cash proceeds of $295 million, which resulted in a pre-tax loss on sale of $187 million. Refer to the “Acquisitions and Divestitures” footnote in the consolidated financial statements for more information on these transactions. There were no other property divestitures resulting in a significant gain or loss on sale during 2017 or 2016.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Year Ended December 31,	
	2017	2016
Notes	$ 133,123	$ 187,374
Amortization of debt issue costs, discounts and premiums	31,715	335,569
Credit agreement	24,971	32,885

Other	1,279	1,792
Total	$ 191,088	$ 557,620

The decrease in interest expense of $367 million between periods was mainly attributable to a decrease in amortization of debt issue costs, discounts and premiums and lower interest costs incurred on our notes during 2017 as compared to 2016. The decrease in amortization of debt issue costs, discounts and premiums of $304 million was due to (i) a non-cash charge of $244 million for the acceleration of unamortized debt discounts in connection with the December 2016 conversions of our Mandatory Convertible Notes, (ii) a $40 million decrease in debt discount and debt issue cost amortization related to the exchange and subsequent conversion to common stock of $1.6 billion of notes during 2016, (iii) a non-cash charge of $14 million for the acceleration of unamortized debt discounts in connection with the August 2016 induced exchange of a portion of our Mandatory Convertible Notes, and (iv) a $6 million non-cash charge for the acceleration of unamortized debt issuance costs in connection with a reduction of the aggregate commitments under our credit agreement in March 2016. The $54 million decrease in note interest was primarily due to (i) the conversions of the

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New Convertible Notes in May 2016 and the Mandatory Convertible Notes in the second half of 2016, resulting in a $39 million decrease in note interest during 2017, and (ii) the redemption of the 2018 Senior Subordinated Notes in February 2017, resulting in a $16 million decrease between periods.

Our weighted average debt outstanding during 2017 was $3.3 billion versus $5.0 billion for 2016. Our weighted average effective cash interest rate was 4.8% during 2017 compared to 4.4% during 2016.

Loss on Extinguishment of Debt. During 2017, we redeemed all of the remaining $275 million aggregate principal amount of 2018 Senior Subordinated Notes and recognized a $2 million loss on extinguishment of debt. During 2016, we recognized a net loss on extinguishment of debt of $42 million. In March 2016, we completed the exchange of $477 million aggregate principal amount of our senior notes and senior subordinated notes for the same aggregate principal amount of New Convertible Notes, and recognized a $91 million gain on extinguishment of debt. Subsequently, during the second quarter of 2016, the holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 10.5 million shares of our common stock, and we recognized a $188 million loss on extinguishment of debt upon conversion. In June and July 2016, we completed the exchange of $1.1 billion aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes for the same aggregate principal amount of Mandatory Convertible Notes, and recognized a $57 million gain on extinguishment of debt. Subsequently in July 2016, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 8.3 million shares of our common stock, and we recognized a $3 million gain on extinguishment of debt upon conversion. In August 2016, we induced the exchange of an additional $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 1.2 million shares of our common stock, and we recognized a $4 million debt inducement expense.

Income Tax Benefit. Income tax benefit for 2017 totaled $483 million as compared to a benefit of $88 million for 2016, an increase of $395 million that was mainly related to (i) a $259 million non-cash charge in 2016 resulting from an ownership shift as defined under Section 382 of the Internal Revenue Code (“IRC”) which will limit our usage of certain net operating losses and tax credits in the future, (ii) $174 million of permanent tax differences recognized in 2016 associated with the issuance and subsequent conversion of the New Convertible Notes and the Mandatory Convertible Notes, (iii) $42 million of net income tax benefits resulting from a reduction in the U.S. federal statutory tax rate upon enactment of the TCJA in December 2017, (iv) $294 million in higher pre-tax loss between periods, and (v) the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017. These decreases were partially offset by the establishment of a full valuation allowance against our net deferred tax assets in 2017 as wells as the tax impact of the $835 million impairment charge at our Redtail field, which charge was incurred after the date of enactment of the TCJA and was therefore effected at the new federal tax rate of 21%.

Our effective tax rates for 2017 and 2016 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate increased from 6.1% in 2016 to 28.1% for 2017. This increase was mainly the result of the IRC Section 382 limitation on our net operating losses and tax credits recognized in 2016, as well as permanent tax differences recognized during 2016 associated with the issuance and subsequent conversions of the New Convertible Notes and the Mandatory Convertible Notes, income tax benefits resulting from enactment of the TCJA and the partial release of a valuation allowance on net operating losses in connection with the sale of the FBIR Assets in the third quarter of 2017. These increases in our effective tax rate were partially offset by the recognition of a full valuation allowance on our net deferred tax assets in 2017 and the tax impact of the impairment charge at our Redtail field after the date of enactment of the TCJA.

Liquidity and Capital Resources

Overview. At December 31, 2018, we had $14 million of cash on hand and $4.3 billion of equity, while at December 31, 2017, we had $879 million of cash on hand and $3.9 billion of equity. Cash on hand at December 31, 2017 consisted of the remaining proceeds from the issuance of our 2026 Notes in December 2017 and was used to redeem the 2019 Notes in January 2018.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 67% and 68% of our total production in 2018 and 2017, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of February 20, 2019, we had derivative contracts covering the sale of approximately 37% of our forecasted 2019 oil production volumes. For a list of all of our outstanding derivatives as of February 20, 2019, refer to Item 7A, “Quantitative and Qualitative Disclosures about Market Risk”.

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Cash Flows from 2018 Compared to 2017. During 2018, we generated $1.1 billion of cash provided by operating activities, an increase of $515 million from 2017. Cash provided by operating activities increased primarily due to higher crude oil, NGL, and natural gas production volumes and higher realized sales prices for oil and NGLs, as well as lower GTC and exploration costs. These positive factors were partially offset by lower realized sales prices for natural gas, as well as an increase in cash settlements paid on our derivative contracts, production and ad valorem taxes, lease operating expenses, cash general and administrative expenses and cash interest expense for 2018 compared to 2017. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses during 2018.

During 2018, cash flows from operating activities and cash on hand were used to finance the redemption of the remaining $961 million of 2019 Senior Notes, including the redemption premium, $814 million of drilling and development expenditures, $143 million of oil and gas property acquisitions, and $11 million of debt issuance costs.

Cash Flows from 2017 Compared to 2016. During 2017, we generated $577 million of cash provided by operating activities, a decrease of $18 million from 2016. Cash provided by operating activities decreased primarily due to lower crude oil production volumes, a decrease in cash settlements received on our derivative contracts and higher production and ad valorem taxes during 2017. These negative factors were partially offset by higher realized sales prices for oil, NGLs and natural gas, as well as lower cash interest expense, lease operating expenses, general and administrative expenses and exploration costs during 2017 as compared to 2016.

During 2017, cash flows from operating activities plus $930 million in proceeds from the sale of oil and gas properties were used to finance $831 million of drilling and development expenditures, $550 million of net repayments under our credit agreement, the redemption of $275 million of our 2018 Senior Subordinated Notes, $21 million of oil and gas property acquisitions and $13 million of debt issuance costs.

Exploration and Development Expenditures. The following chart details our E&D expenditures incurred by core area (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Northern Rocky Mountains	$ 741,378	$ 601,737	$ 348,610
Central Rocky Mountains	82,660	292,826	170,256
Permian Basin (1)	-	-	33,266
Other (2)	7,985	17,866	1,462
Total incurred	$ 832,023	$ 912,429	$ 553,594

(1) During 2016, we sold our interest in the Bravo Dome field in New Mexico and our enhanced oil recovery project at North Ward Estes.

(2) Other primarily includes non-core oil and gas properties located in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming.

We continually evaluate our capital needs and compare them to our capital resources. Our 2019 E&D budget is a range of $800 million to $840 million, which we expect to fund substantially with net cash provided by operating activities and cash on hand. The forecasted midpoint of our 2019 E&D budget of $820 million represents a slight decrease from the $832 million incurred on E&D expenditures during 2018. We believe that should additional attractive acquisition opportunities arise or E&D expenditures exceed $820 million, we will be able to finance additional capital expenditures through agreements with industry partners, divestitures of certain oil and gas property interests, borrowings under our credit agreement or by accessing the capital markets. Our level of E&D expenditures is largely discretionary, and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plan over the next twelve months and for the foreseeable future. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels (including availability under our credit agreement), access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Credit Agreement.   Whiting Oil and Gas, our wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2018 had a borrowing base and aggregate commitments of $2.4 billion and $1.75 billion, respectively. As of

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December 31, 2018, we had $1.75 billion of available borrowing capacity under the credit agreement, which was net of $2 million in letters of credit outstanding, with no borrowings outstanding.

The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of our borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of December 31, 2018, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 2020 Convertible Senior Notes) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. Interest under the credit agreement accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below.

Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the credit agreement.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of our restricted subsidiaries (as defined in the credit agreement). As of December 31, 2018, the credit agreement required us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to the last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. We were in compliance with our covenants under the credit agreement as of December 31, 2018. For further information on the loan security related to our credit agreement, refer to the "Long-Term Debt" footnote in the notes to consolidated financial statements.

Senior Notes. In December 2017, we issued at par $1.0 billion of 6.625% Senior Notes due January 2026 (the "2026 Senior Notes"). In March 2015, we issued at par $750 million of 6.25% Senior Notes due April 2023 (the "2023 Senior Notes"). In September 2013, we issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the "2019 Senior Notes") and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively the "2021 Senior Notes" and together with the 2023 Senior Notes and the 2026 Senior Notes, the "Senior Notes").

Exchange of Senior Notes for Convertible Notes. During 2016, we exchanged (i) $139 million aggregate principal amount of our 2019 Senior Notes, (ii) $326 million aggregate principal amount of our 2021 Senior Notes, and (iii) $342 million aggregate principal amount of our 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $807 million

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aggregate principal amount of these convertible notes was converted into approximately 19.8 million shares of our common stock pursuant to the terms of the notes.

Redemption of 2019 Senior Notes. In January 2018, we paid $1.0 billion to redeem all of the then outstanding $961 million aggregate principal amount of our 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with proceeds from the issuance of our 2026 Senior Notes and borrowings under our credit agreement.

2020 Convertible Senior Notes. In March 2015, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the "2020 Convertible Senior Notes"). During 2016, we exchanged $688 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million aggregate principal amount of these mandatory convertible senior notes was converted into approximately 17.8 million shares of our common stock pursuant to the terms of the notes.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of December 31, 2018, we have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at our election. Our intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder's option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at a current conversion rate of 6.4102 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, we will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of December 31, 2018, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Note Covenants. The indentures governing the Senior Notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. Additionally, these indentures contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, make certain other restricted payments, redeem or repurchase our capital stock, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of December 31, 2018. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of December 31, 2018 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below. This table does not include amounts payable under contracts where we cannot predict with accuracy the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent upon the price of crude oil in effect at the time of settlement, and any penalties that may be incurred for underdelivery under our physical delivery

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contracts. For further information on these contracts refer to the "Derivative Financial Instruments" footnote in the notes to consolidated financial statements and "Delivery Commitments" in Item 2 of this Annual Report on Form 10 K.

	Payments due by period (in thousands)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 2,843,980	$ -	$ 1,435,684	$ 408,296	$ 1,000,000
Cash interest expense on debt (2)	722,813	155,673	259,163	172,901	135,076
Asset retirement obligations (3)	135,834	4,290	20,774	13,733	97,037
Water disposal agreement (4)	103,081	20,318	40,635	31,298	10,830
Real estate leases (5)	49,588	7,407	8,836	8,205	25,140
Pipeline transportation agreements (6)	45,736	9,406	19,118	11,100	6,112
Drilling rig contracts (7)	29,557	29,557	-	-	-
Purchase obligations (8)	15,743	7,706	7,756	100	181
Automobile and equipment leases (9)	9,839	4,216	5,100	523	-
Total	$ 3,956,171	$ 238,573	$ 1,797,066	$ 646,156	$ 1,274,376

(1) Long-term debt consists of the principal amounts of the Senior Notes and the 2020 Convertible Senior Notes.

(2) Cash interest expense on the Senior Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the 2020 Convertible Senior Notes is estimated assuming no principal repayments or conversions prior to maturity. Commitment fees on the credit agreement are estimated assuming no principal borrowings, repayments or changes to commitments through the April 2023 instrument due date.

(3) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants, facilities and offshore platforms.

(4) We have a water disposal agreement which expires in 2024 under which we have contracted for the transportation and disposal of the produced water from our Redtail field. Under the terms of the agreement, we are obligated to provide a minimum volume of produced water or else pay for any deficiencies at the price stipulated in the contract. As a result of our reduced development operations at our Redtail field, we have made and expect to continue to make deficiency payments under this contract. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements for more information on this contract and the related deficiency payments.

(5) We currently lease 222,900 square feet of administrative office space in Denver, Colorado under an agreement expiring in October 2019. We have entered into an agreement to lease 135,175 square feet of administrative office space in Denver beginning on or before November 1, 2019, which will replace our existing Denver office lease. In addition, we lease 81,875 square feet of office and warehouse space in North Dakota through 2023 and 44,500 square feet of office space in Midland, Texas expiring in 2020. We have sublet the majority of our office space in Midland, Texas to a third party for the remaining lease term. The offsetting rental income has not been included in the table above.

(6) Our pipeline transportation agreements consist of contracts through 2025 with various third parties to facilitate the delivery of our produced oil, gas and NGLs to market. These contracts require either fixed monthly reservation fees or commitments to deliver minimum volumes at fixed rates in exchange for dedicated pipeline capacity. If minimum volume commitments are not met, we are required to pay any deficiencies at the prices stipulated in the contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments

presented above.

(7) As of December 31, 2018, we had five drilling rigs under short-term contracts that expire in 2019. As of December 31, 2018, early termination of these contracts would require termination penalties of $22 million, which would be in lieu of paying the remaining drilling commitments under these contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

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(8) Our purchase obligations consist of take-or-pay arrangements to buy volumes of water for use in the fracture stimulation process under agreements through 2027. Under the terms of the agreements, we are obligated to purchase a minimum volume of water or else pay for any deficiencies at the prices stipulated in the contracts. Under one of these purchase obligations, we have committed to buy certain volumes of water through 2020 for wells we complete in our Redtail field. As a result of our reduced development operations in this field, we have made and expect to continue to make deficiency payments under this contract. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements for more information on this contract and the related deficiency payments.

(9) Our automobile and equipment leases consist of non-cancelable long-term lease agreements with various suppliers for vehicles utilized by our operations and field personnel and a variety of office and field equipment. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operating, development and exploration activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the "Summary of Significant Accounting Policies" footnote in the notes to consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements in accordance with GAAP and SEC rules and regulations requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties and our asset retirement obligations. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates is a function of (i) the quality and quantity of available data, (ii) the interpretation of that data, (iii) the accuracy of various mandated economic assumptions, and (iv) the judgments of the persons preparing the estimates.

External petroleum engineers independently estimated all of the proved reserve quantities included in this Annual Report on Form 10 K. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2018. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. For example, if the crude oil and natural gas prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2018 would have increased by 8 MMBOE (1%) or decreased by 11 MMBOE (2%), respectively, and the pre-tax PV10% of our proved reserves would have increased by $1.2 billion (21%) or decreased by $1.2 billion (21%), respectively. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates and impairment calculations (when impairment indicators arise) in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing their undiscounted future net cash flows to their net book values at the end of each period. If their net capitalized costs exceed undiscounted future net cash flows, the cost of the property is written down to “fair value”, which is determined using discounted future net cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. In addition to proved property impairments, we provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred. Individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average lease-term lives.

Asset Retirement Obligation. Our asset retirement obligations (“ARO”) consist of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate; the inflation rate; and future advances in technology. In periods subsequent to the initial measurement of an ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Derivative Instruments. All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the “normal purchase normal sale” exclusion or other derivative scope exceptions. We do not currently apply hedge accounting to any of our outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

We determine the recorded amounts of our derivative instruments measured at fair value utilizing third-party valuation specialists. We review these valuations, including the related model inputs and assumptions, and analyze changes in fair value measurements between periods. We corroborate such inputs, calculations and fair value changes using various methodologies, and review unobservable inputs for reasonableness utilizing relevant information from other published sources. When available, we utilize counterparty valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as the assumptions used in these valuations are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize costless collars and swaps which are generally placed with major financial institutions, as well as crude oil sales and delivery contracts. We use hedging to help ensure that we have adequate funding for our capital programs and to manage returns on our drilling programs and acquisitions. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

We value our costless collars and swaps using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. We value our long-term crude oil sales and delivery contracts based on a probability-weighted income approach which considers various assumptions, including quoted spot prices for commodities, market differentials for crude oil and U.S. Treasury rates. The discount rates used in the fair values of these instruments include a measure of nonperformance risk by the counterparty or us, as appropriate.

In addition, we evaluate the terms of our convertible debt and other contracts, if any, to determine whether they contain embedded components that are required to be bifurcated and accounted for separately as derivative financial instruments.

Income Taxes and Uncertain Tax Positions. We provide for income taxes in accordance with FASB ASC Topic 740 – Income Taxes (“ASC 740”). We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions, particularly as they relate to prevailing oil and natural gas prices.

On December 22, 2017, Congress passed the Tax Cuts and Jobs Act (the “TCJA”). The new legislation significantly changed the U.S. corporate tax law by, among other things, lowering the U.S. corporate income tax rate from 35% to 21% beginning in January 2018, implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries. The SEC issued Staff Accounting Bulletin No. 118 (“SAB 118”), which allowed registrants to record provisional amounts during a one-year “measurement period” similar to that used to account for business combinations, however, the measurement period was deemed to have ended earlier once the registrant had obtained, prepared and analyzed the information necessary to finalize its accounting. During the measurement period, impacts of the law were to be recorded at the time a reasonable estimate for all or a portion of the effects could be made, and provisional amounts recognized and adjusted as information became available, prepared or analyzed. As a result of the new legislation, we recognized the provisional impacts of the revaluation of our deferred tax assets and liabilities as of the date of enactment. We did not recognize any measurement period adjustments to these provisional amounts, and as of December 31, 2018, our accounting for the TCJA was complete.

ASC 740 requires uncertain income tax positions to meet a more-likely-than-not realization threshold to be recognized in the financial statements. Under ASC 740, uncertain tax positions that previously failed to meet the more-likely-than-not threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized uncertain tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition. We recognize revenue in accordance with FASB ASC Topic 606 – Revenue from Contracts with Customers, which we adopted effective January 1, 2018 using the modified retrospective approach. Refer to the "Summary of Significant Accounting Policies" footnote in the notes to the consolidated financial statements for more information on our adoption of this new accounting standard.

We predominantly derive our revenue from the sale of produced oil, NGLs and natural gas. Revenue is recognized when we meet our performance obligation to deliver the product and control is transferred to the customer. We receive payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the amount of production delivered and the price we will receive can be reasonably estimated and amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. Variances between our estimated revenue and actual payments are recorded in the month the payment is received. However, differences have been and are insignificant.

Accounting for Business Combinations. We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 – Business Combinations, and involves the use of significant judgment.

Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess, if any, of the consideration given to acquire an entity over the net amounts assigned to its assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity is recognized immediately to earnings as a gain from bargain purchase.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present values of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

The business combinations completed during the prior three years consisted of oil and gas properties. In general, the consideration we have paid to acquire these properties or companies was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition and consequently, there was no goodwill nor any bargain purchase gains recognized on our business combinations.

Effects of Inflation and Pricing

Although commodity prices began to recover from previous lows during 2018, the cost of oil field goods and services has remained relatively consistent with 2017 and 2016 levels. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase in the near term, higher demand in the industry could result in increases in the costs of materials, services and personnel.

Forward Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect”, “intend”, “plan”, “estimate”, “anticipate”, “believe” or “should” or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: declines in, or extended periods of low oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness, ability to comply with debt covenants and periodic redeterminations of the borrowing base under our credit agreement; the geographic concentration of our operations; impacts to financial statements as a result of impairment write-downs; federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; inaccuracies of our reserve estimates or our assumptions underlying them; risks relating to any unforeseen liabilities of ours; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital

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expenditures budget; our ability to obtain external capital to finance exploration and development operations; our ability to successfully complete asset dispositions and the risks related thereto; unforeseen underperformance of or liabilities associated with acquired properties; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; availability of, and risks associated with, transport of oil and gas; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; the potential impact of changes in laws that could have a negative effect on the oil and gas industry; our ability to replace our oil and natural gas reserves; negative impacts from litigation and legal proceedings; any loss of our senior management or technical personnel; competition in the oil and gas industry; cyber security attacks or failures of our telecommunication systems; and other risks described under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10 K. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Annual Report on Form 10 K.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on 2018 production, our income (loss) before income taxes for 2018 would have moved up or down $185 million for each 10% change in oil prices per Bbl, $15 million for each 10% change in NGL prices per Bbl and $8 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars and swaps, although we evaluate and have entered into other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Crude Oil Costless Collars and Swaps. The collared hedges shown in the table below have the effect of providing a protective floor while allowing us to share in upward pricing movements. While these hedges are designed to reduce our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. The fair value of these crude oil costless collars at December 31, 2018 was a net asset of $68 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2018 would cause a decrease of $25 million or an increase of $32 million, respectively, in this fair value asset.

The swap contracts shown in the table below entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. While the fixed-price swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of upward price movements. There were no swaps outstanding as of December 31, 2018.

Our outstanding commodity derivative contracts as of February 20, 2019 are summarized below:

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Price (Per Bbl)
				Fixed Price
Swaps	Crude oil	07/2019 to 09/2019	150,000	$58.94
	Crude oil	10/2019 to 12/2019	150,000	$58.94
				Floor/Ceiling
Collars	Crude oil	01/2019 to 03/2019	1,100,000	$50.91/$75.55
	Crude oil	04/2019 to 06/2019	1,100,000	$50.91/$75.55
	Crude oil	07/2019 to 09/2019	700,000	$51.64/$77.32
	Crude oil	10/2019 to 12/2019	700,000	$51.64/$77.32

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. At December 31, 2018, we had no borrowings outstanding under our credit agreement. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate senior notes, but changes in interest rates do affect the fair values of these notes.

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The interest rate on our 2020 Convertible Senior Notes is fixed at 1.25%, and as such, we are not subject to any direct risk of loss related to fluctuations in interest rates. However, changes in interest rates do affect the fair value of this debt instrument, which could impact the amount of gain or loss that we recognize in earnings upon conversion of the notes. Refer to the "Long-Term Debt" and "Fair Value Measurements" footnotes in the notes to consolidated financial statements for more information on the material terms and fair values of the 2020 Convertible Senior Notes.

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Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation

Denver, Colorado

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, cash flows, and equity for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of 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 accounting principles generally accepted in the United States of America.

We have also 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 (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

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/ DELOITTE & TOUCHE LLP

Denver, Colorado

February 27, 2019

We have served as the Company's auditor since 2003.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share data)

	December 31, 2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,607	$ 879,379
Accounts receivable trade, net	294,468	284,214
Derivative assets	68,342	-
Prepaid expenses and other	22,009	26,035
Total current assets	398,426	1,189,628
Property and equipment:		
Oil and gas properties, successful efforts method	12,195,659	11,293,650
Other property and equipment	134,212	134,524
Total property and equipment	12,329,871	11,428,174
Less accumulated depreciation, depletion and amortization	(5,003,509)	(4,244,735)
Total property and equipment, net	7,326,362	7,183,439
Other long-term assets	34,785	29,967
TOTAL ASSETS	$ 7,759,573	$ 8,403,034
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ -	$ 958,713
Accounts payable trade	42,520	32,761
Revenues and royalties payable	228,284	171,028
Accrued capital expenditures	73,178	69,744
Accrued interest	55,080	40,971
Accrued lease operating expenses	37,499	36,865
Accrued liabilities and other	33,872	51,590
Taxes payable	31,357	28,771
Derivative liabilities	-	132,525
Accrued employee compensation and benefits	35,141	30,360
Total current liabilities	536,931	1,553,328
Long-term debt	2,792,321	2,764,716
Deferred income taxes	1,373	-
Asset retirement obligations	131,544	129,206
Other long-term liabilities	27,088	36,642
Total liabilities	3,489,257	4,483,892
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 225,000,000 shares authorized; 92,067,216 issued and 91,018,692 outstanding as of December 31, 2018 and 92,094,837 issued and 90,698,889 outstanding as of December 31, 2017	92	92
Additional paid-in capital	6,414,170	6,405,490
Accumulated deficit	(2,143,946)	(2,486,440)

Total equity	4,270,316	3,919,142
TOTAL LIABILITIES AND EQUITY	$ 7,759,573	$ 8,403,034

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

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)

	Year Ended December 31,		
	2018	2017	2016
OPERATING REVENUES			
Oil, NGL and natural gas sales	$ 2,081,414	$ 1,481,435	$ 1,284,982
OPERATING EXPENSES			
Lease operating expenses	311,895	278,919	313,168
Gathering, transportation, compression and other	48,105	90,574	78,845
Production and ad valorem taxes	171,823	120,870	111,837
Depreciation, depletion and amortization	781,329	948,939	1,171,582
Exploration and impairment	67,368	936,177	121,468
General and administrative	123,250	124,288	146,878
Derivative (gain) loss, net	17,170	122,847	(587)
Loss on sale of properties	1,949	401,113	184,567
Amortization of deferred gain on sale	(11,354)	(12,963)	(14,570)
Total operating expenses	1,511,535	3,010,764	2,113,188
INCOME (LOSS) FROM OPERATIONS	569,879	(1,529,329)	(828,206)
OTHER INCOME (EXPENSE)			
Interest expense	(197,474)	(191,088)	(557,620)
Loss on extinguishment of debt	(31,968)	(1,540)	(42,236)
Interest income and other	3,430	1,316	1,292
Total other expense	(226,012)	(191,312)	(598,564)
INCOME (LOSS) BEFORE INCOME TAXES	343,867	(1,720,641)	(1,426,770)
INCOME TAX EXPENSE (BENEFIT)			
Current	-	(7,291)	(7,190)
Deferred	1,373	(475,688)	(80,456)
Total income tax expense (benefit)	1,373	(482,979)	(87,646)
NET INCOME (LOSS)	342,494	(1,237,662)	(1,339,124)
Net loss attributable to noncontrolling interests	-	14	22
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 342,494	$ (1,237,648)	$ (1,339,102)
INCOME (LOSS) PER COMMON SHARE (1)			
Basic	$ 3.77	$ (13.65)	$ (21.27)
Diluted	$ 3.73	$ (13.65)	$ (21.27)
WEIGHTED AVERAGE SHARES OUTSTANDING (1)			
Basic	90,953	90,683	62,967
Diluted	91,869	90,683	62,967

(1) All share and per share amounts have been retroactively adjusted for the 2016 period to reflect the Company's one-for-four reverse stock split in November 2017, as described in Note 8 to these consolidated financial statements.

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

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 342,494	$ (1,237,662)	$ (1,339,124)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	781,329	948,939	1,171,582
Deferred income tax expense (benefit)	1,373	(475,688)	(80,456)
Amortization of debt issuance costs, debt discount and debt premium	30,700	31,715	335,569
Stock-based compensation	12,669	21,641	25,647
Amortization of deferred gain on sale	(11,354)	(12,963)	(14,570)
Loss on sale of properties	1,949	401,113	184,567
Oil and gas property impairments	45,288	899,853	75,622
Exploratory dry hole costs	-	-	134
Loss on extinguishment of debt	31,968	1,540	42,236
Non-cash derivative (gain) loss	(139,831)	131,129	151,151
Payment for settlement of commodity derivative contract	(61,036)	-	-
Other, net	(6,706)	(9,255)	(10,185)
Changes in current assets and liabilities:			
Accounts receivable trade, net	(11,571)	(110,879)	155,416
Prepaid expenses and other	4,026	(444)	586
Accounts payable trade and accrued liabilities	11,368	(24,953)	(62,774)
Revenues and royalties payable	56,751	23,799	(32,185)
Taxes payable	2,586	(10,776)	(8,206)
Net cash provided by operating activities	1,092,003	577,109	595,010
CASH FLOWS FROM INVESTING ACTIVITIES			
Drilling and development capital expenditures	(813,981)	(830,552)	(539,208)
Acquisition of oil and gas properties	(142,723)	(21,429)	(4,718)
Other property and equipment	(1,096)	(4,596)	(9,255)
Proceeds from sale of oil and gas properties	4,746	929,974	313,355
Deposit received on properties held for sale	-	-	17,250
Net cash provided by (used in) investing activities	(953,054)	73,397	(222,576)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings under credit agreement	2,214,265	1,900,000	1,310,000
Repayments of borrowings under credit agreement	(2,214,265)	(2,450,000)	(1,560,000)
Issuance of 6.625% Senior Notes due 2026	-	1,000,000	-
Redemption of 6.5% Senior Subordinated Notes due 2018	-	(275,121)	-
Redemption of 5.0% Senior Notes due 2019	(990,023)	-	-
Early conversion payments for New Convertible Notes	-	-	(41,919)
Debt issuance costs	(10,709)	(13,150)	(22,499)
Restricted stock used for tax withholdings	(4,744)	(6,081)	(844)

Proceeds from stock options exercised	755	-	-
Net cash provided by (used in) financing activities	$ (1,004,721)	$ 155,648	$ (315,262)

(Continued)

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2018	2017	2016
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	$ (865,772)	$ 806,154	$ 57,172
CASH, CASH EQUIVALENTS AND RESTRICTED CASH			
Beginning of period	879,379	73,225	16,053
End of period	$ 13,607	$ 879,379	$ 73,225
SUPPLEMENTAL CASH FLOW DISCLOSURES			
Income taxes paid (refunded), net	$ (32)	$ 49	$ (1,044)
Interest paid, net of amounts capitalized	$ 152,665	$ 163,151	$ 239,963
NONCASH INVESTING ACTIVITIES			
Accrued capital expenditures and accounts payable related to property additions	$ 90,358	$ 80,762	$ 65,052
NONCASH FINANCING ACTIVITIES (1)			

The accompanying notes are an integral part of these consolidated financial statements. (Concluded)

(1) Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for a discussion of (i) the Company’s exchange of senior notes and senior subordinated notes for convertible notes and the subsequent conversions of such notes, and (ii) the Company’s exchange of senior notes, convertible senior notes and senior subordinated notes for mandatory convertible notes and the subsequent conversions of such notes.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands)

	Common Stock Shares (1)	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity
BALANCES - January 1, 2016	51,610	$ 206	$ 4,659,868	$ 90,530	$ 4,750,604	$ 7,984	$ 4,758,588
Net loss	-	-	-	(1,339,102)	(1,339,102)	(22)	(1,339,124)
Issuance of common stock upon conversion of convertible notes	39,386	158	1,535,296	-	1,535,454	-	1,535,454
Reduction of equity component of 2020 Convertible Senior Notes upon extinguishment, net	-	-	(63,330)	-	(63,330)	-	(63,330)
Recognition of beneficial conversion features on convertible notes	-	-	232,801	-	232,801	-	232,801
Restricted stock issued	1,005	4	(4)	-	-	-	-
Restricted stock forfeited	(182)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(26)	-	(844)	-	(844)	-	(844)
Stock-based compensation	-	-	25,647	-	25,647	-	25,647
BALANCES - December 31, 2016	91,793	367	6,389,435	(1,248,572)	5,141,230	7,962	5,149,192
Net loss	-	-	-	(1,237,648)	(1,237,648)	(14)	(1,237,662)
Conveyance of third party ownership interest in Sustainable	-	-	-	-	-	(7,948)	(7,948)

Water Resources, LLC							
Reverse stock split	-	(276)	276	-	-	-	-
Restricted stock issued	707	2	(2)	-	-	-	-
Restricted stock forfeited	(261)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(144)	-	(6,081)	-	(6,081)	-	(6,081)
Stock-based compensation	-	-	21,641	-	21,641	-	21,641
Cumulative effect of change in accounting principle	-	-	220	(220)	-	-	-
BALANCES - December 31, 2017	92,095	92	6,405,490	(2,486,440)	3,919,142	-	3,919,142
Net income	-	-	-	342,494	342,494	-	342,494
Exercise of stock options	16	-	755	-	755	-	755
Restricted stock issued	451	-	-	-	-	-	-
Restricted stock forfeited	(351)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(144)	-	(4,744)	-	(4,744)	-	(4,744)
Stock-based compensation	-	-	12,669	-	12,669	-	12,669
BALANCES - December 31, 2018	92,067	$ 92	$ 6,414,170	$ (2,143,946)	$ 4,270,316	$ -	$ 4,270,316

(1) All common share amounts have been retroactively adjusted for the 2016 period to reflect the Company's one-for-four reverse stock split in November 2017, as described in Note 8 to these consolidated financial statements.

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

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WHITING PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company engaged in the development, production, acquisition and exploration of crude oil, NGLs and natural gas primarily in the Rocky Mountains region of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation and its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements have been prepared in accordance with GAAP and SEC rules and regulations and include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (i) oil and natural gas reserves; (ii) impairment tests of long-lived assets; (iii) depreciation, depletion and amortization; (iv) asset retirement obligations; (v) assignment of fair value and allocation of purchase price in connection with business combinations, including the determination of any resulting goodwill; (vi) valuations of the Company's reporting unit used in impairment tests of goodwill; (vii) income taxes; (viii) accrued liabilities; (ix) valuation of derivative instruments; and (x) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Reclassifications—Certain prior period balances in the consolidated statements of operations have been reclassified to conform to the current year presentation. These include the reclassification of gathering, transportation, compression and other expenses and ad valorem taxes from previously reported lease operating expenses in the consolidated statements of operations. For all periods presented, gathering, transportation, compression and other expenses are presented as a separate caption and ad valorem taxes are combined with production taxes. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Cash and Cash Equivalents—Cash equivalents consist of demand deposits and highly liquid investments which have an original maturity of three months or less.

Restricted cash at December 31, 2016 related to a deposit received in connection with the sale of Whiting's interests in the Robinson Lake and Belfield gas processing plants in North Dakota. The use of these funds was restricted per the terms of the purchase agreement until the sale transaction closed on January 1, 2017. Refer to the "Acquisitions and Divestitures" footnote for further information on this transaction.

Accounts Receivable Trade—Whiting's accounts receivable trade consist mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, Whiting typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected within two months, and to date, the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. At December 31, 2018 and 2017, the Company had an allowance for doubtful accounts of $12 million and $17 million, respectively.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment and totaled $23 million and $24 million as of December 31, 2018 and 2017, respectively. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or net realizable value. Oil in tanks is included in prepaid expenses and other and totaled $5 million and $7 million as of December 31, 2018 and 2017, respectively.

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Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a unit-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. Costs of drilling exploratory wells are initially capitalized but are charged to expense if the well is determined to be unsuccessful.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed undiscounted future net cash flows, then the cost of the property is written down to fair value. Fair value for oil and gas properties is generally determined based on discounted future net cash flows. Impairment expense for proved properties totaled $835 million for the year ended December 31, 2017, which is reported in exploration and impairment expense.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

Unproved. Unproved properties consist of costs to acquire undeveloped leases as well as purchases of unproved reserves. Undeveloped lease costs and unproved reserve acquisitions are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on average lease-term lives and the historical experience of developing acreage in a particular prospect. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense for unproved properties totaled $37 million, $59 million and $73 million for the years ended December 31, 2018, 2017 and 2016, respectively, which is reported in exploration and impairment expense.

Exploratory. Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. Costs incurred for exploratory wells that find reserves, which cannot yet be classified as proved, continue to be capitalized if (i) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs, net of any salvage value, are expensed.

Other Property and Equipment—Other property and equipment consists of materials and supplies inventories, carried at weighted-average cost, and furniture and fixtures, buildings, leasehold improvements and automobiles, which are stated at cost and depreciated using the straight-line method over their estimated useful lives ranging from 4 to

30 years.

Debt Issuance Costs—Debt issuance costs related to the Company's senior notes, convertible senior notes and senior subordinated notes are included as a deduction from the carrying amount of long-term debt in the consolidated balance sheets and are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the credit facility are included in other long-term assets and are amortized to interest expense on a straight-line basis over the term of the agreement.

Debt Discounts and Premiums—Debt discounts and premiums related to the Company's senior notes and convertible notes are included as a deduction from or addition to the carrying amount of the long-term debt in the consolidated balance sheets and are amortized to interest expense using the effective interest method over the term of the related notes.

Derivative Instruments—The Company enters into derivative contracts, primarily costless collars and swaps, to manage its exposure to commodity price risk. Whiting follows FASB ASC Topic 815 – Derivatives and Hedging, to account for its derivative financial instruments. All derivative instruments, other than those that meet the "normal purchase normal sale" exclusion, are recorded on the balance sheet as either an asset or liability measured at fair value. Gains and losses from changes in the fair value of derivative instruments are recognized immediately in earnings, unless the derivative meets specific hedge accounting criteria and the derivative has been designated as a hedge. The Company does not currently apply hedge accounting to any of its outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

Cash flows from derivatives used to manage commodity price risk are classified in operating activities along with the cash flows of the underlying hedged transactions. The Company does not enter into derivative instruments for speculative or trading purposes. Refer to the "Derivative Financial Instruments" footnote for further information.

Asset Retirement Obligations and Environmental Costs—Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The Company follows FASB ASC Topic 410 – Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when a well is completed or acquired or when an asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a unit-of-production basis over the proved developed reserves of the related asset. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells, and such revisions result in adjustments to the related capitalized asset and corresponding liability.

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties.

Deferred Gain on Sale—The deferred gain on sale relates to the sale of 18,400,000 Whiting USA Trust II ("Trust II") units, and is amortized to income based on the unit-of-production method.

Revenue Recognition—Revenues are predominantly derived from the sale of produced oil, NGLs and natural gas. In May 2014, the FASB issued Accounting Standards Update No. 2014 09, Revenue from Contracts with Customers ("ASU 2014 09"). The FASB subsequently issued various ASUs which provided additional implementation guidance, and these ASUs collectively make up FASB ASC Topic 606 – Revenue from Contracts with Customers ("ASC 606"). The objective of ASC 606 is to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. ASC 606 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented or (ii) recognition of a cumulative-effect adjustment as of the date of initial application. The Company adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. The adoption did not have an impact on the Company's net income or cash flows, and the Company did not record a cumulative-effect adjustment to retained earnings as a result. However, the adoption did result in changes to the classification of certain fees incurred under pipeline gathering and transportation agreements and gas processing agreements, as well as certain costs attributable to non-operated properties, which led to an overall decrease in total revenues with a corresponding decrease in gathering, transportation, compression and other expenses under the new standard. Refer to the "Revenue

Recognition” footnote for further information on the Company’s implementation of this standard.

In accordance with ASC 606, oil and gas revenues are recognized when the performance obligation to deliver the product is met and control is transferred to the customer. Payments for product sales are received one to three months after delivery. At the end of each month when the performance obligation is satisfied and the amount of production delivered and the price received can be reasonably estimated, amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. Variances between estimated revenue and actual payments are recorded in the month the payment is received. However, differences have been and are insignificant.

Taxes collected and remitted to governmental agencies on behalf of customers are not included in revenues or costs and expenses.

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General and Administrative Expenses—General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to the working interest owners that participate in oil and gas properties operated by Whiting.

Stock-based Compensation Expense—The Company has share-based employee compensation plans that provide for the issuance of various types of stock-based awards, including shares of restricted stock, restricted stock units, performance shares, performance share units and stock options, to employees and non-employee directors. The Company determines compensation expense for share-settled awards granted under these plans based on the grant date fair value, and such expense is recognized on a straight-line basis over the requisite service period of the award. The Company determines compensation expense for cash-settled awards granted under these plans based on the fair value of such awards at the end of each reporting period. Cash-settled awards are recorded as a liability in the consolidated balance sheets, and gains and losses from changes in fair value are recognized immediately in earnings. The Company accounts for forfeitures of share-based awards as they occur. Refer to the "Stock-Based Compensation" footnote for further information.

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company's contributions for 2018, 2017 and 2016 were $7 million, $8 million and $8 million, respectively. Employees vest in employer contributions at 20% per year of completed service up to five years.

Acquisition Costs—Acquisition related expenses, which consist of external costs directly related to the Company's acquisitions, such as advisory, legal, accounting, valuation and other professional fees, are expensed as incurred.

Maintenance and Repairs—Maintenance and repair costs that do not extend the useful lives of property and equipment are charged to expense as incurred. Major replacements, renewals and betterments are capitalized.

Income Taxes—Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized. The Company's uncertain tax positions must meet a more-likely-than-not realization threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income attributable to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted and performance stock awards, outstanding stock options and contingently issuable shares of convertible debt to be settled in cash, all using the treasury stock method. In addition, the diluted earnings per share calculation for the year ended December 31, 2016 considers the effect of convertible debt issued and converted during 2016, using the if-converted method for periods prior to their actual conversions. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, NGLs and natural gas. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Concentration of Credit Risk—Whiting is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuing review. The following tables present the percentages by purchaser that accounted for 10% or more of the Company's total oil, NGL and natural gas sales for the years ended December 31, 2018, 2017 and 2016.

Year Ended December 31, 2018		
United Energy Trading, LLC	17	%
Tesoro Crude Oil Co	14	%
Philips 66 Company	11	%

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Year Ended December 31, 2017	
Tesoro Crude Oil Co	18 %

Year Ended December 31, 2016	
Tesoro Crude Oil Co	15 %
Jamex Marketing LLC	12 %

Commodity derivative contracts held by the Company are with eleven counterparties, all of which are participants in Whiting's credit facility and all of which have investment-grade ratings from Moody's and Standard & Poor's. As of December 31, 2018, outstanding derivative contracts with JP Morgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Capital One, N.A. represented 18%, 15% and 15%, respectively, of total crude oil volumes hedged.

Recently Issued Accounting Pronouncements—In February 2016, the FASB issued Accounting Standards Update No. 2016 02, Leases ("ASU 2016 02"). The objective of this ASU is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. The FASB subsequently issued various ASUs which provided additional implementation guidance. ASU 2016 02 and its amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. The standard permits retrospective application through recognition of a cumulative-effect adjustment at the beginning of either the earliest reporting period presented or the period of adoption. The Company adopted ASU 2016-02 effective January 1, 2019 using a cumulative-effect adjustment as of the adoption date. Whiting elected certain practical expedients available under the standard including those that permit the Company to not (i) reassess prior conclusions reached under FASB ASC Topic 840 – Leases for lease identification, lease classification and initial direct costs, (ii) evaluate existing or expired land easements under the new standard and (iii) separate lease and non-lease components contained within a single agreement. Additionally, the Company has elected the short-term lease recognition exemption and therefore, leases with a term of one year or less will not be recognized on the consolidated balance sheet. Whiting is substantially complete with the assessment of its existing accounting policies and documentation, implementation of lease accounting software and enhancement of its internal controls. Adoption of the standard will result in the recognition of additional lease assets and liabilities on Whiting's consolidated balance sheet as well as additional disclosures. The adoption is not expected to have a material impact to the Company's consolidated statement of operations. As of December 31, 2018, the Company had approximately $254 million of contractual obligations related to its water disposal agreements, purchase obligations, pipeline transportation agreements, drilling rig contracts, real estate leases and automobile and equipment leases, and certain of these contracts will be recorded on its consolidated balance sheet under this standard.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at December 31, 2018 and 2017 are as follows (in thousands):

	December 31,	
	2018	2017
Proved leasehold costs	$ 2,729,593	$ 2,622,576

Unproved leasehold costs	122,687	137,694
Costs of completed wells and facilities	9,182,384	8,288,591
Wells and facilities in progress	160,995	244,789
Total oil and gas properties, successful efforts method	12,195,659	11,293,650
Accumulated depletion	(4,937,579)	(4,185,301)
Oil and gas properties, net	$ 7,258,080	$ 7,108,349

3. ACQUISITIONS AND DIVESTITURES

2018 Acquisitions and Divestitures

On July 31, 2018, the Company completed the acquisition of certain oil and gas properties located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The properties consist of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped

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acreage. The revenue and earnings from these properties since the acquisition date are included in the Company's consolidated financial statements for the year ended December 31, 2018 and are not material. Pro forma revenue and earnings for the acquired properties are not material to the Company's consolidated financial statements and have not been presented accordingly.

The acquisition was recorded using the acquisition method of accounting. The following table summarizes the preliminary allocation of the $127 million adjusted purchase price (which is still subject to post-closing adjustments) to the tangible assets acquired and liabilities assumed in this acquisition based on their relative fair values at the acquisition date, which did not result in the recognition of goodwill or a bargain purchase gain. As the purchase price is further adjusted for post-close adjustments and as oil and gas property valuations are completed, the final purchase price allocation may result in a different allocation to the tangible assets from that which is presented in the table below (in thousands):

Cash consideration	$ 126,938
Fair value of assets and liabilities acquired:	
Proved oil and gas properties	$ 107,701
Unproved oil and gas properties	21,769
Total fair value of oil and gas properties acquired	129,470
Asset retirement obligations	2,532
Total fair value of net assets acquired	$ 126,938

2017 Acquisitions and Divestitures

On September 1, 2017, the Company completed the sale of its interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, (the "FBIR Assets") for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

On January 1, 2017, the Company completed the sale of its 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and its 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments). The Company used the net proceeds from this transaction to repay a portion of the debt outstanding under its credit agreement.

There were no significant acquisitions during the year ended December 31, 2017.

2016 Acquisitions and Divestitures

In July 2016, the Company completed the sale of its interest in its enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including Whiting's interest in certain CO_2 properties in the McElmo Dome field in Colorado and certain other related assets and liabilities (the "North Ward Estes Properties") for a cash purchase price of $300 million (before closing adjustments). The sale was effective July 1, 2016 and resulted in a pre-tax loss on sale of $187 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

In addition to the cash purchase price, the buyer agreed to pay Whiting $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million (the "Contingent Payment"). The Company determined that this Contingent Payment was an embedded derivative and reflected it at fair value in the consolidated financial statements prior to settlement. On July 19, 2017, the buyer paid $35 million to Whiting to settle this Contingent Payment, resulting in a pre-tax gain of $3 million. Refer to the "Derivative Financial Instruments" footnote for more information on this embedded derivative instrument.

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4. LONG TERM DEBT

Long-term debt, including the current portion, consisted of the following at December 31, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
5.0% Senior Notes due 2019	$ -	$ 961,409
1.25% Convertible Senior Notes due 2020	562,075	562,075
5.75% Senior Notes due 2021	873,609	873,609
6.25% Senior Notes due 2023	408,296	408,296
6.625% Senior Notes due 2026	1,000,000	1,000,000
Total principal	2,843,980	3,805,389
Unamortized debt discounts and premiums	(28,994)	(50,945)
Unamortized debt issuance costs on notes	(22,665)	(31,015)
Total debt	2,792,321	3,723,429
Less current portion of long-term debt	-	(958,713)
Total long-term debt	$ 2,792,321	$ 2,764,716

The following table shows five succeeding fiscal years of anticipated maturities for the Company's long-term debt as of December 31, 2018 (in thousands):

	2019	2020	2021	2022	2023
Long-term debt	$ -	$ 562,075	$ 873,609	$ -	$ 408,296

Credit Agreement

Whiting Oil and Gas, the Company's wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2018 had a borrowing base of $2.4 billion and aggregate commitments of $1.75 billion. As of December 31, 2018, the Company had $1.75 billion of available borrowing capacity under the credit agreement, which was net of $2 million in letters of credit outstanding with no borrowings outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of the borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, the Company could be forced to immediately repay a portion of its debt outstanding under the credit agreement.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of December 31, 2018, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 2020 Convertible Senior Notes) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. Interest under the credit agreement accrues at the Company’s option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company incurs commitment fees as set forth in the table below

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on the unused portion of the aggregate commitments of the lenders under the credit agreement, which are included as a component of interest expense.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit the Company’s ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company’s ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the Company’s restricted subsidiaries (as defined in the credit agreement). As of December 31, 2018, there were no retained earnings free from restrictions. The credit agreement requires the Company, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters’ EBITDAX ratio of not greater than 4.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of December 31, 2018.

The obligations of Whiting Oil and Gas under the credit agreement are collateralized by a first lien on substantially all of Whiting Oil and Gas’ and Whiting Resource Corporation’s properties. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of its subsidiaries as security for its guarantee.

Senior Notes, Convertible Senior Notes and Senior Subordinated Notes

The following table summarizes the material terms of the Company’s senior notes and convertible senior notes outstanding at December 31, 2018:

	2020 Convertible Senior Notes	2021 Senior Notes	2023 Senior Notes	2026 Senior Notes
Outstanding principal (in thousands)	$ 562,075	$ 873,609	$ 408,296	$ 1,000,000
Interest rate	1.25%	5.75%	6.25%	6.625%
Maturity date	Apr 1, 2020	Mar 15, 2021	Apr 1, 2023	Jan 15, 2026
Interest payment dates	Apr 1, Oct 1	Mar 15, Sep 15	Apr 1, Oct 1	Jan 15, Jul 15
Make-whole redemption date (1)	N/A (2)	Dec 15, 2020	Jan 1, 2023	Oct 15, 2025

(1) On or after these dates, the Company may redeem the applicable series of notes, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed, together with accrued and unpaid interest up to the redemption date. At any time prior to these dates, the Company may redeem the notes at a redemption price that includes an applicable premium as defined in the indentures to such notes.
(2) The indenture governing the 1.25% Convertible Senior Notes due 2020 does not allow for optional redemption by the Company prior to the maturity date.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the “2018 Senior Subordinated Notes”).

In September 2013, the Company issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the “2019 Senior Notes”) and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively, the “2021 Senior Notes”). The debt premium recorded in connection with the issuance of the 2021 Senior

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Notes is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.5% per annum.

In March 2015, the Company issued at par $750 million of 6.25% Senior Notes due April 2023 (the “2023 Senior Notes”).

In December 2017, the Company issued at par $1.0 billion of 6.625% Senior Notes due January 2026 (the “2026 Senior Notes” and together with the 2019 Senior Notes, the 2021 Senior Notes and the 2023 Senior Notes, the “Senior Notes”). The Company used the net proceeds from this offering to redeem on January 26, 2018 all of the then outstanding 2019 Senior Notes. Refer to “Redemption of the 2019 Senior Notes” below for more information on the redemption of the 2019 Senior Notes.

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. In March 2016, the Company completed the exchange of $477 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $49 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $97 million aggregate principal amount of its 2019 Senior Notes, (iii) $152 million aggregate principal amount of its 2021 Senior Notes, and (iv) $179 million aggregate principal amount of its 2023 Senior Notes, for $477 million aggregate principal amount of convertible senior notes and convertible senior subordinated notes (the “New Convertible Notes”). This exchange transaction was accounted for as an extinguishment of debt for each portion of the Senior Notes and 2018 Senior Subordinated Notes that was exchanged. As a result, Whiting recognized a $91 million gain on extinguishment of debt in 2016, which was net of a $4 million non-cash charge for the acceleration of unamortized debt issuance costs and debt premium on the original notes. Each series of New Convertible Notes was recorded at fair value upon issuance, with the difference between the principal amount of the notes and their fair values, totaling $95 million, recorded as a debt discount. The aggregate debt discount of $185 million recorded upon issuance of the New Convertible Notes also included $90 million related to the fair value of the holders’ conversion options, which were embedded derivatives that met the criteria to be bifurcated from their host contracts and accounted for separately. Refer to the “Derivative Financial Instruments” footnote for more information on these embedded derivatives.

During the second quarter of 2016, holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 10.5 million shares of the Company’s common stock. Upon conversion, the Company paid $46 million in cash consisting of early conversion payments to the holders of the notes, as well as all accrued and unpaid interest on such notes. As a result of the conversions, Whiting recognized a $188 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs and debt discount on the notes. As of June 30, 2016, no New Convertible Notes remained outstanding.

Exchange of Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. In July 2016, the Company completed the exchange of $405 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated Notes for the same aggregate principal amount of new mandatory convertible senior notes and mandatory convertible senior subordinated notes. Refer to “Mandatory Convertible Notes” below for more information on these exchange transactions.

Redemption of 2018 Senior Subordinated Notes. In February 2017, the Company paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $2 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs on the notes. As of March 31, 2017, no 2018 Senior Subordinated Notes remained outstanding.

Redemption of 2019 Senior Notes. On January 26, 2018, the Company paid $1.0 billion to redeem all of the remaining $961 million aggregate principal amount of the 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with proceeds from the issuance of the 2026 Senior Notes and borrowings under its credit agreement. As a result of the redemption, the Company recognized a $31 million loss on extinguishment of debt, which included the redemption premium and a non-cash charge for the acceleration of unamortized debt issuance costs on the notes. As of March 31, 2018, no 2019 Senior Notes remained outstanding.

2020 Convertible Senior Notes—In March 2015, the Company issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the "2020 Convertible Senior Notes") for net proceeds of $1.2 billion, net of initial purchasers' fees of $25 million. On June 29, 2016, the Company exchanged $129 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes, and on July 1, 2016, the Company exchanged $559 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Refer to "Mandatory Convertible Notes" below for more information on these exchange transactions.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of December 31, 2018, the Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company's intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder's option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at a current conversion rate of 6.4102 shares of Whiting's common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of December 31, 2018, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the 2020 Convertible Senior Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2020 Convertible Senior Notes and the estimated fair value of the liability component was recorded as a debt discount and is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.6% per annum. The fair value of the liability component of the 2020 Convertible Senior Notes as of the issuance date was estimated at $1.0 billion, resulting in a debt discount at inception of $238 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2020 Convertible Senior Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital within shareholders' equity, and will not be remeasured as long as it continues to meet the conditions for equity classification.

Transaction costs related to the 2020 Convertible Senior Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component were recorded as a reduction to the carrying value of long-term debt on the consolidated balance sheet and are being amortized to interest expense over the term of the notes using the effective interest method. Issuance costs attributable to the equity component were recorded as a charge to additional paid-in capital within shareholders' equity.

The 2020 Convertible Senior Notes consisted of the following at December 31, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017

Liability component		
Principal	$ 562,075	$ 562,075
Less: unamortized note discount	(29,504)	(51,666)
Less: unamortized debt issuance costs	(2,340)	(4,178)
Net carrying value	$ 530,231	$ 506,231
Equity component (1)	$ 136,522	$ 136,522

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $50 million of deferred taxes as of December 31, 2018 and 2017.

Interest expense recognized on the 2020 Convertible Senior Notes related to the stated interest rate and amortization of the debt discount totaled $29 million, $28 million and $43 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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Mandatory Convertible Notes—On June 29, 2016, the Company completed the exchange of $129 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible notes, and on July 1, 2016, the Company completed the exchange of $964 million aggregate principal amount of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $26 million aggregate principal amount of 2018 Senior Subordinated Notes, (ii) $42 million aggregate principal amount of 2019 Senior Notes, (iii) $559 million aggregate principal amount of 2020 Convertible Senior Notes, (iv) $174 million aggregate principal amount of 2021 Senior Notes, and (v) $163 million aggregate principal amount of 2023 Senior Notes, for the same aggregate principal amount of new mandatory convertible notes (together the "Mandatory Convertible Notes").

These transactions were accounted for as extinguishments of debt for the portions of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes that were exchanged. As a result, Whiting recognized a $57 million gain on extinguishment of debt, which was net of a $113 million charge for the non-cash write-off of unamortized debt issuance costs, debt discounts and debt premium on the original notes. In addition, Whiting recorded a $63 million reduction to the equity component of the 2020 Convertible Senior Notes, which was net of deferred taxes. The Mandatory Convertible Notes were recorded at fair value upon issuance with the difference between the principal amount of the notes and their fair values, totaling $69 million, recorded as a debt discount. The Mandatory Convertible Notes contained contingent beneficial conversion features, the intrinsic value of which was recognized in additional paid-in capital at the time the contingency was resolved, resulting in an additional debt discount of $233 million. The aggregate debt discount of $302 million was being amortized to interest expense over the term of the notes using the effective interest method.

The July 1, 2016 note exchange transactions triggered an ownership shift as defined under Section 382 of the Internal Revenue Code due to the "deemed share issuance" that resulted from the note exchanges. This triggering event will limit the Company's usage of certain of its net operating losses and tax credits in the future. Refer to the "Income Taxes" footnote for more information.

During the second half of 2016, the entire $1,093 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 28.9 million shares of the Company's common stock pursuant to the terms of the notes. As a result of these conversions, Whiting recognized (i) a $259 million non-cash charge for the acceleration of unamortized debt discounts on the notes, which is included in interest expense in the consolidated statements of operations, and (ii) a $1 million net loss on extinguishment of debt. As of December 31, 2016, no Mandatory Convertible Notes remained outstanding.

Security and Guarantees

The 2021 Senior Notes, 2023 Senior Notes, 2026 Senior Notes and the 2020 Convertible Senior Notes are unsecured obligations of Whiting Petroleum Corporation and these unsecured obligations are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement.

The Company's obligations under the 2021 Senior Notes, 2023 Senior Notes, 2026 Senior Notes and the 2020 Convertible Senior Notes are guaranteed by the Company's 100% owned subsidiaries, Whiting Oil and Gas, Whiting US Holding Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (the "Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. Any subsidiaries other than these Guarantors are minor subsidiaries as defined by Rule 3 10(h)(6) of Regulation S X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The current portions at December 31, 2018 and 2017 were $4 million and $5 million, respectively, and have been included in accrued liabilities and other in

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the consolidated balance sheets. The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
Asset retirement obligation at January 1	$ 134,237	$ 177,004
Additional liability incurred	11,981	7,727
Revisions to estimated cash flows(1)	(17,197)	(52,947)
Accretion expense	11,405	13,809
Obligations on sold properties	(676)	(6,988)
Liabilities settled	(3,916)	(4,368)
Asset retirement obligation at December 31	$ 135,834	$ 134,237

(1) Revisions to estimated cash flows during the year ended December 31, 2017 are primarily attributable to the deferral of the estimated timing of abandonment of a large number of Whiting's producing properties resulting from increases in commodity prices used in the calculation of the Company's reserves as of December 31, 2017, which lengthened the economic lives of these properties. In addition, during 2017 there were decreases in the estimates of future costs required to plug and abandon wells in certain fields in the Northern Rocky Mountains.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features which are required to be bifurcated and accounted for separately as derivatives.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. Whiting primarily enters into derivative contracts such as crude oil costless collars and swaps, as well as sales and delivery contracts, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility, thereby ensuring adequate funding for the Company's capital programs and facilitating the management of returns on drilling programs and acquisitions. The Company does not enter into derivative contracts for speculative or trading purposes.

Crude Oil Costless Collars. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements.

The table below details the Company's costless collar derivatives entered into to hedge forecasted crude oil production revenues as of December 31, 2018.

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price for Crude Oil (per Bbl)
Collars (1)	Jan - Dec 2019	9,900,000	$51.21 - $77.14
	Total	9,900,000	

(1) Subsequent to December 31, 2018, the Company entered into swap contracts for 900,000 Bbl of crude oil volumes and additional costless collars for 900,000 Bbl of crude oil volumes for the second half of 2019.

Crude Oil Sales and Delivery Contract. As of December 31, 2017, the Company had a long-term crude oil sales and delivery contract for oil volumes produced from its Redtail field in Colorado. Under the terms of the agreement, Whiting had committed to deliver certain fixed volumes of crude oil through April 2020. The Company determined it was not probable that future oil production from its Redtail field would be sufficient to meet the minimum volume requirements specified in this contract; accordingly, the Company would not settle this contract through physical delivery of crude oil volumes. As a result, Whiting determined that this contract would not qualify for the "normal purchase normal sale" exclusion and has therefore reflected the contract at fair value in the consolidated financial

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statements. As of December 31, 2017, the estimated fair value of this derivative contract was a liability of $63 million. On February 1, 2018, Whiting paid $61 million to the counterparty to settle all future minimum volume commitments under this agreement. Accordingly, this crude oil sales and delivery contract was fully terminated and the fair value of this corresponding derivative was therefore zero as of that date.

Embedded Derivatives—In March 2016, the Company issued convertible notes that contained debtholder conversion options which the Company determined were not clearly and closely related to the debt host contracts, and the Company therefore bifurcated these embedded features and reflected them at fair value in the consolidated financial statements. During the second quarter of 2016, the entire aggregate principal amount of these notes was converted into shares of the Company's common stock, and the fair value of these embedded derivatives as of December 31, 2016 was therefore zero.

In July 2016, the Company entered into a purchase and sale agreement with the buyer of its North Ward Estes Properties, whereby the buyer agreed to pay Whiting additional proceeds of $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million. The Company determined that this NYMEX-linked contingent payment was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at its estimated fair value in the consolidated financial statements. On July 19, 2017, the buyer paid $35 million to Whiting to settle this NYMEX-linked contingent payment, and accordingly, the embedded derivative's fair value was zero as of December 31, 2018 and 2017.

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion or other derivative scope exceptions. The following table summarizes the effects of derivative instruments on the consolidated statements of operations for the years ended December 31, 2018, 2017 and 2016 (in thousands):

		(Gain) Loss Recognized in Income		
Not Designated as	Statement of Operations	Year Ended December 31,		
ASC 815 Hedges	Classification	2018	2017	2016
Commodity contracts	Derivative (gain) loss, net	$ 17,170	$ 104,138	$ 58,771
Embedded derivatives	Derivative (gain) loss, net	-	18,709	(59,358)
Total		$ 17,170	$ 122,847	$ (587)

Offsetting of Derivative Assets and Liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all the Company's derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

		December 31, 2018 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities

Derivative assets				
Commodity contracts - current	Derivative assets	$ 69,735	$ (1,393)	$ 68,342
Total derivative assets		$ 69,735	$ (1,393)	$ 68,342
Derivative liabilities				
Commodity contracts - current	Derivative liabilities	$ 1,393	$ (1,393)	$ -
Total derivative liabilities		$ 1,393	$ (1,393)	$ -

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	December 31, 2017 (1)		
	Gross Recognized	Gross	Net Recognized Fair Value
Not Designated as			