

WHITING PETROLEUM CORP
Form 10-K
February 23, 2017
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, 2016

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.)

80290 2300

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1700 Broadway, Suite 2300

Denver, Colorado

(Address of principal executive offices) (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 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 Securities 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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
	(Do not check if a smaller reporting company)		

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, 2016: \$3,357,000,000.

Number of shares of the Registrant's common stock outstanding at February 15, 2017: 362,698,464 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2017 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.

“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.

“delay rental” Consideration paid to the lessor by a lessee to extend the terms of an oil and natural gas lease in the absence of drilling operations and/or production that is contractually required to hold the lease. This consideration is generally required to be paid on or before the anniversary date of the oil and gas lease during its primary term, and typically extends the lease for an additional year.

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

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“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 Bbl.

“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.

“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. See the footnote to the Proved Reserves table in Item 1. “Business” of this Annual Report on Form 10-K for more information.

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“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, 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.

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“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 of Kodiak Oil & Gas Corp. (the “Kodiak Acquisition”) discussed in the “Acquisitions and Divestitures” footnote in the notes to the consolidated financial statements. As a result of lower crude oil prices during 2015 and 2016, we significantly reduced our level of capital spending to more closely align with our cash flows generated from operations, and have focused our drilling activity on projects that provide the highest rate of return. In addition, 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, 2016, our estimated proved reserves totaled 615.5 MMBOE and our 2016 average daily production was 129.9 MBOE/d, which results in an average reserve life of approximately 12.9 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2016, their corresponding pre-tax PV10% values, and our fourth quarter 2016 average daily production rates, as well as our company’s total standardized measure of discounted future net cash flows as of December 31, 2016:

	Proved Reserves (1)					Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2016 Average Daily Production (MBOE/d)
	Oil	NGLs	Natural Gas	Total	%		
Core Area	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	Oil		
Northern Rocky Mountains (3)	281.9	81.8	522.3	450.8	63%	\$ 2,397	108.9
Central Rocky Mountains (4)	109.3	19.6	191.2	160.7	68%	285	9.2
Other (5)	3.6	0.1	2.2	4.0	90%	16	0.8
Total	394.8	101.5	715.7	615.5	64%	\$ 2,698	118.9

Discounted Future Income Tax Expense (6)	-
Standardized Measure of Discounted Future Net Cash Flows	\$ 2,698

- (1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from an oil price of \$42.75 per Bbl and a gas price of \$2.49 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, 2016 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 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

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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.

(6) Based on the 12-month average oil and natural gas prices used in the computation of pre-tax PV10% as of December 31, 2016, our future net income generated over the life of our proved reserves is expected to be less than our net operating loss carryforward deductions and therefore, under the Standardized Measure, there is no deduction for federal or state income taxes.

During 2016, we incurred \$554 million in exploration and development (“E&D”) expenditures, including \$504 million for the drilling of 89 gross (48.2 net) wells. All of these new wells resulted in productive completions.

Our current 2017 E&D budget is \$1.1 billion, which we expect to fund substantially with net cash provided by our operating activities, proceeds from property divestitures, cash on hand, borrowings under our credit facility or by accessing the capital markets. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would 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

During 2015 and 2016, in response to sustained lower crude oil prices, we divested of a large number of non-core oil and gas properties that no longer matched the profile of properties we desire to own. In addition, in January 2017 we closed on the sale of our interests in two gas processing plants located in the Williston Basin for aggregate sales proceeds of \$375 million. Refer to the “Subsequent Events” footnote in the notes to consolidated financial statements for more information on this transaction. Our significant acquisitions and divestitures during the last two years are summarized below.

Acquisitions. There were no significant acquisitions during the years ended December 31, 2016 and 2015.

2016 Divestitures. In July 2016, we completed the sale of our interest in our enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including our interest in certain CO₂ 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. In addition to the cash purchase price, the buyer has agreed to pay us \$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 Contingent Payment will be made at the option of the buyer either in cash on July 31, 2018 or in the form of a secured promissory note, accruing interest at 8% per annum with a maturity date of July 29, 2022. The North Ward Estes Properties consisted of estimated proved reserves of 120.3 MMBOE as of December 31, 2015, representing 15% of our proved reserves as of that date, and generated 8.6 MBOE/d (or 6%) of our June 2016 average daily net production.

2015 Divestitures. In December 2015, we completed the sale of a fresh water delivery system, a produced water gathering system and four saltwater disposal wells located in Weld County, Colorado, effective December 16, 2015, for aggregate sales proceeds of \$75 million (before closing adjustments).

In June 2015, we completed the sale of our interests in certain non-core oil and gas wells, effective June 1, 2015, for aggregate sales proceeds of \$150 million (before closing adjustments) resulting in a pre-tax loss on sale of \$118 million. The properties included over 2,000 gross wells in 132 fields across 10 states. The properties had estimated proved reserves of 20.9 MMBOE as of December 31, 2014, representing 3% of our proved reserves as of that date, and generated 5.3 MBOE/d (or 3%) of our May 2015 average daily production.

In April 2015, we completed the sale of our interests in certain non-core oil and gas wells, effective May 1, 2015, for aggregate sales proceeds of \$108 million (before closing adjustments) resulting in a pre-tax gain on sale of \$29 million. The properties are located in 187 fields across 14 states, and predominately consisted of assets that were previously included in the underlying properties of Whiting USA Trust I. The properties had estimated proved reserves of 8.9 MMBOE as of December 31, 2014, representing 1% of our total proved reserves as of that date, and generated 2.7 MBOE/d (or 2%) of our March 2015 average daily net production.

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Also during the year ended December 31, 2015, we completed several immaterial divestiture transactions for the sale of our interests in certain non-core oil and gas wells and undeveloped acreage, for aggregate sales proceeds of \$176 million (before closing adjustments) resulting in a pre-tax gain on sale of \$28 million. These properties had estimated proved reserves of 23.4 MMBOE as of December 31, 2014, representing 3% of our total proved reserves as of that date. The properties generated a combined total of approximately 4.4 MBOE/d of average daily net production, based on production rates at each of the respective closing dates.

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:

Developing Existing Properties. The development of large resource plays such as our Williston Basin and Denver Julesburg Basin (“DJ Basin”) projects has become one of our central objectives. As of December 31, 2016, we have assembled approximately 736,000 gross (443,800 net) developed and undeveloped acres in the Williston Basin located in North Dakota and Montana. As of December 31, 2016, we had four drilling rigs operating in this area.

During 2016, we entered into two separate wellbore participation agreements related to wells drilled in the Williston Basin, which helped allow us to continue completion activity in this area.

At our Redtail field in the DJ Basin in Weld County, Colorado, we have assembled approximately 157,200 gross (132,200 net) developed and undeveloped acres. As of December 31, 2016, we had one drilling rig operating in the DJ Basin. We suspended completion operations in this area beginning in the second quarter of 2016; however, we plan to resume completion activity in early 2017. 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.

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 equity and debt issuances, bank borrowings, internally generated cash flows and certain oil and gas property divestitures, as appropriate, to maintain our financial position. As a result of sustained lower crude oil prices in 2015 and 2016, we significantly reduced our level of capital spending to more closely align with our cash flows generated from operations, and have focused our drilling activity on projects that provide the highest rate of return. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement or fund our E&D expenditures. For example, during 2015 and 2016 we sold a large number of non-core oil and gas properties 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, swaps and crude oil sales and delivery contracts to provide an attractive base commodity price level. As of January 3, 2017, we had derivative contracts covering the sale of approximately 49% of our forecasted 2017 oil production.

Growing Through Accretive Acquisitions. Since 2003, we have completed 21 separate significant acquisitions of producing properties for total estimated proved reserves of 445.2 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, 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, such as the Kodiak Acquisition, which closed in 2014 and significantly expanded our presence in the Williston Basin.

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, 2016, we had interests in 4,687 gross (1,917 net) productive wells on approximately 849,300 gross (517,200 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 12.9 years based on year-end 2016 proved reserves and 2016 production.

Experienced Management and Technical Teams. Our management team averages 30 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 33 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

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Commitment to Technology. In each of our core operating areas, we have accumulated extensive geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Data provided by our in-house, state-of-the-art rock analysis laboratory is used to support real-time drilling and completion decisions, and to help us further understand unconventional oil plays. Our technical team has access to approximately 9,400 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand-held computers in the field. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

We continue to advance our completion techniques, including significantly increasing proppant volumes, utilizing diverter agents to better distribute fluid and proppant across individual zones, varying the number of completion stages, and employing new fracture stimulation fluids, including slickwater. We plan to continue use of these state-of-the-art completion designs on wells we drill throughout 2017, while also testing new diversion technology and more efficient placement and drillout of down-hole plugs.

Proved Reserves

Our estimated proved reserves as of December 31, 2016 are summarized by core area in the table below. See “Reserves” in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

	Oil	NGLs	Natural Gas	Total	% of Total	Estimated Future Capital Expenditures (1) (in millions)
Northern Rocky Mountains (2):	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	Proved	
PDP	168.1	49.4	314.5	270.0	60%	
PDNP	0.9	0.3	2.0	1.5	-%	
PUD	112.9	32.1	205.8	179.3	40%	
Total proved	281.9	81.8	522.3	450.8	100%	\$ 1,847.7
Central Rocky Mountains (3):						
PDP	10.2	2.0	18.6	15.2	10%	
PDNP	0.4	0.1	0.6	0.6	-%	
PUD	98.7	17.5	172.0	144.9	90%	
Total proved	109.3	19.6	191.2	160.7	100%	\$ 1,753.9
Other (4):						
PDP	3.2	0.1	1.6	3.6	90%	
PDNP	0.4	0.0	0.6	0.4	10%	

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Total proved	3.6	0.1	2.2	4.0	100%	\$ 4.3
Total Company:						
PDP	181.5	51.5	334.7	288.8	47%	
PDNP	1.7	0.4	3.2	2.5	-%	
PUD	211.6	49.6	377.8	324.2	53%	
Total proved	394.8	101.5	715.7	615.5	100%	\$ 3,605.9

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- (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.

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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 facilities. In areas where there is no practical access to pipelines, oil is trucked or transported by rail 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, 2016 and 2014. For the year ended December 31, 2015, no individual purchaser accounted for 10% or more of our total oil, NGL and natural gas sales. We believe that the loss of any individual purchaser 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, 2016:

Tesoro Crude Oil Co	15%
Jamex Marketing LLC	12%

Year Ended December 31, 2014:

Plains Marketing LP	17%
Shell Trading US	10%
Bridger Trading LLC	10%

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, 2016. We are therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act.

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Among other things, we are required to obtain prior BOEM approval for any exploration plans we pursue and for our lease development and production plans. BOEM regulations also 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 an 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.

Public protests and media attention related to permitting and construction of the Dakota Access Pipeline in North Dakota near the Standing Rock Indian Reservation may attract additional attention to oil pipeline operations and regulation. We do not expect any resulting impacts to oil pipeline transportation would affect our operations in any way that is of material difference from those of 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.

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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 braking systems, 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 27 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 of 2016 became law. The PIPES Act strengthens PHMSA’s safety authority, including an expansion of its ability to issue emergency orders, which were 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 for resale of natural gas 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.

The FERC implements the Outer Continental Shelf Lands Act pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access and non-discriminatory transportation service. One of the FERC's principal goals in carrying out this Act's mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

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 in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry historically has always 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.

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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 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 addressing design issues for underground storage facilities, including wells, wellbore tubing and casing. 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.

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

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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 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 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 them 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

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determination that revision of the regulations is not necessary. 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 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.

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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. 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.

After the closing of the Kodiak Acquisition, the EPA contacted us to discuss Kodiak’s responses to a June 2014 information request from the EPA under Section 114(a) of the CAA. In addition, in July 2015 and March 2016, we received information requests from the EPA under Section 114(a) of the CAA. The information requests relate to tank batteries used in our Williston Basin operations and our compliance with certain regulatory requirements at those locations for the control of air pollutant emissions from those facilities. We have responded to the EPA’s July 2015 and March 2016 information requests, and such responses were also provided to the North Dakota Department of Health (the “NDDoH”), with whom the EPA was coordinating in making the requests. The EPA has sole authority to enforce CAA violations on the Fort Berthold Indian Reservation in North Dakota, and, to date, no formal federal enforcement action has been commenced in connection with this matter for our North Dakota tribal properties beyond receipt of the noted information requests. We are unable to predict the ultimate outcome of possible federal enforcement with respect to our North Dakota tribal properties, or other exclusively federal requirements at any of our North Dakota properties, at this time, which could result in civil penalties or require us to undertake corrective actions, or both.

In connection with the above EPA inquiries, in October 2016, the NDDoH concurrently filed in the North Dakota District Court for Burleigh County (the “Court”) a complaint against, and a settlement with, us regarding tank operation and other inspection-related alleged violations of North Dakota’s air pollution control laws. In November 2016, the Court issued its order accepting this settlement as its final judgment to resolve the issues raised in the complaint. This settlement addresses approximately 94 percent of our North Dakota properties but does not address our North Dakota tribal property operations or exclusively federal requirements applicable to all of our North Dakota properties, which are governed by the EPA. In the settlement, we and a significant number of North Dakota operators have worked with the NDDoH to develop inspection and repair measures to detect and prevent emissions from facilities even more effectively going forward. We believe these measures will be included in settlements between the NDDoH and each participating operator. We and the NDDoH, pending Court approval of the settlement, have agreed that we will pay a civil penalty of \$1.2 million, of which \$1.1 million may be reduced by up to 60 percent by early and continued implementation of the aforementioned inspection and repair measures and a quality control policy. We anticipate being able to qualify for all available penalty reductions. The settlement is not an admission by us of any violation.

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 Colorado, Montana and North Dakota, 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 recompleting 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.

Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. In March 2015, the U.S. Department of the Interior released a final rule addressing (i) hydraulic fracturing on federal and Indian oil and natural gas leases to require validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes, (ii) disclosure of

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chemicals used in hydraulic fracturing to the Bureau of Land Management, (iii) higher standards for interim storage of recovered waste fluids from hydraulic fracturing, and (iv) measures to lower the risk of cross-well contamination with chemicals and fluids used in fracturing operations. 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. Also, 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. 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 causal 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.

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, 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 GHG. 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. The proposed rule has not 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

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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. The Court of Appeals for the D.C. Circuit heard oral arguments on the Clean Power Plan in September 2016, but has not yet issued a decision. President Trump has indicated that he is opposed to the Clean Power Plan, and the new administration could withdraw the rule and potentially repropose it, or seek to invalidate the EPA's prior determination that GHGs present an endangerment to public health and the environment. Either action is likely to be challenged in court, which could delay implementation of any new rules.

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 is issuing new 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 marine, coastal or human environment. Similarly, NEPA requires the 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. 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 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, 2017, we had approximately 850 full-time employees, including 27 senior level geoscientists and 63 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, in oil-producing countries or affecting other oil-producing activity, such as the recent conflicts in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the effects of global credit, financial and economic issues;
- developments of United States energy infrastructure, such as the recent delays in constructing the Dakota Access Pipeline;
- weather conditions;
- technological advances affecting energy consumption;
- current and anticipated changes to domestic and foreign governmental regulations, including those expected as a result of the election of Donald Trump to the U.S. Presidency;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
 - 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 continues to experience low prices, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

Oil prices have fallen significantly since reaching highs of over \$105.00 per Bbl in June 2014, dropping below \$27.00 per Bbl in February 2016. Natural gas prices have also declined from over \$4.80 per MMBtu in April 2014 to below \$1.70 per MMBtu in March 2016. Although oil and natural gas prices have begun to recover from the lows experienced during the first quarter of 2016, forecasted prices for both oil and natural gas remain low.

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 have reduced, and may further 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 instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.”

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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. Please read “— Reserve estimates depend on many assumptions that may turn out to be inaccurate...” later in these Risk Factors 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 the following:

- substantial or extended declines in oil, NGL and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- 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;
- pipeline takeaway and refining and processing capacity; and
- title problems.

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, 2016, we had \$550 million in borrowings and \$11 million in letters of credit outstanding under Whiting Oil and Gas Corporation’s (“Whiting Oil and Gas”) credit facility with \$1.9 billion of available borrowing capacity, as well as \$2,243 million of senior notes outstanding, \$562 million of convertible senior notes outstanding and \$275 million of senior subordinated notes outstanding. On February 2, 2017, we redeemed all \$275 million of our senior subordinated notes outstanding. 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:

- 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 our 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
- when oil and natural gas prices decline, our ability to maintain compliance with our financial covenants becomes more difficult and our borrowing base is subject to reductions, 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

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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 remain at their current levels for a prolonged period or go lower, 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 out of 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.

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

- enter into sale and leaseback transactions.

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, (ii) a total senior secured debt to the last four quarters' EBITDAX ratio of less than 3.0 to 1.0 during the Interim Covenant Period (defined below), and thereafter a total debt to EBITDAX ratio of less than 4.0 to 1.0, and (iii) a ratio of the last four quarters' EBITDAX to consolidated cash interest charges of not less than 2.25 to 1.0 during the Interim Covenant Period. Under the credit agreement, the "Interim Covenant Period" is defined as the period from June 30, 2015 until the earlier of (i) April 1, 2018 or (ii) the commencement of an investment-grade debt rating period.

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 or 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

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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.

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 a \$1.5 billion impairment charge during 2015 for the partial write-down of the North Ward Estes field in Texas and other non-core proved oil and gas properties primarily in Texas, Wyoming, North Dakota and Colorado that were not being developed due to depressed oil and gas prices. Additionally, we recorded a \$62 million impairment charge during 2015 for the partial write-down of our CO₂ development properties in New Mexico and Colorado whose net book values exceeded their undiscounted future net cash flows. 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 Colorado, Montana and North Dakota, 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.

Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. In March 2015, the U.S. Department of the Interior released a final rule addressing (i) hydraulic fracturing on federal and Indian oil and natural

gas leases to require validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes, (ii) disclosure of chemicals used in hydraulic fracturing to the Bureau of Land Management, (iii) higher standards for interim storage of recovered waste fluids from hydraulic fracturing, and (iv) measures to lower the risk of cross-well contamination with chemicals and fluids used in fracturing operations. 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. Also, 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. 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

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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 causal 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.

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.

We have entered into three 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 two are 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. At our Redtail field, we have determined that it is no longer probable that future oil production will be sufficient to meet the minimum volume requirements and we expect to make periodic deficiency payments that currently total \$4.91 per undelivered Bbl (subject to upward adjustment) under one contract and that equal the terminal and transportation fees paid by the counterparty on undelivered barrels, currently \$3.93 per undelivered Bbl (subject to upward adjustment), under the other contract. During 2016 and 2015, total deficiency payments under these contracts amounted to \$43 million and \$15 million, respectively. See “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:

- 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, 2016 were \$42.75 per Bbl and \$2.49 per MMBtu. Actual future prices and costs may differ materially from those used in the estimate. If the 12-month average oil prices used to

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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, 2016 would have decreased by \$181 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, 2016 would have decreased by \$17 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 equity and debt issuances, bank borrowings, internally generated cash flows, agreements with industry partners and oil and gas property divestments. We intend to finance future capital expenditures with cash flow from operations, proceeds from property divestitures, cash on hand and financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- 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.

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. Please read “— Federal, state and local legislative and regulatory initiatives relating to hydraulic

fracturing...” above in these Risk Factors 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.

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In addition, drilling, production and transportation of hydrocarbons bear the inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of air, soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

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, 2016, 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 25% in 2017, 28% in 2018 and 8% in 2019. 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.

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 following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- 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.

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, 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.

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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 2016 we recorded a \$13 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. See “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 2016, we completed 21 separate significant acquisitions of producing properties with a combined purchase price of \$6.4 billion for estimated proved reserves as of the effective dates of the acquisitions of 445.2 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including 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.

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.

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 on 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 indemnification provisions, which could obligate us to substantial liabilities.

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 January 3, 2017, we had contracts covering the sale of 1,300,000 barrels of oil per month for all of 2017, which represents approximately 49% of our forecasted 2017 oil production volumes. All of our oil hedges will expire by December 2018. See “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.

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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. Our three-way collars only provide partial protection against declines in market prices due to the fact that when the market price falls below the sub-floor, the minimum price we will receive will be NYMEX plus the difference between the floor and the sub-floor. 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. 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.

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 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 87% of our net productive oil and natural gas wells, which represents 86% of our proved developed producing reserves as of December 31, 2016. If we do not operate the properties in which we own an interest, we do not have control over normal operating

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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.

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies do, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

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.

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:

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

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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, or the imposition of injunctive relief. 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 regards 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. 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.

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After the closing of the Kodiak Acquisition, the EPA contacted us to discuss Kodiak's responses to a June 2014 information request from the EPA under Section 114(a) of the CAA. In addition, in July 2015 and March 2016, we received information requests from the EPA under Section 114(a) of the CAA. The information requests relate to tank batteries used in our Williston Basin operations and our compliance with certain regulatory requirements at those locations for the control of air pollutant emissions from those facilities. We have responded to the EPA's July 2015 and March 2016 information requests, and such responses were also provided to the North Dakota Department of Health (the "NDDoH"), with whom the EPA was coordinating in making the requests. The EPA has sole authority to enforce CAA violations on the Fort Berthold Indian Reservation in North Dakota, and, to date, no formal federal enforcement action has been commenced in connection with this matter for our North Dakota tribal properties beyond receipt of the noted information requests. We are unable to predict the ultimate outcome of possible federal enforcement with respect to our North Dakota tribal properties, or other exclusively federal requirements at any of our North Dakota properties, at this time, which could result in civil penalties or require us to undertake corrective actions, or both.

In connection with the above EPA inquiries, in October 2016, the NDDoH concurrently filed in the North Dakota District Court for Burleigh County (the "Court") a complaint against, and a settlement with, us regarding tank operation and other inspection-related alleged violations of North Dakota's air pollution control laws. In November 2016, the Court issued its order accepting this settlement as its final judgment to resolve the issues raised in the complaint. This settlement addresses approximately 94 percent of our North Dakota properties but does not address our North Dakota tribal property operations or exclusively federal requirements applicable to all of our North Dakota properties, which are governed by the EPA. In the settlement, we and a significant number of North Dakota operators have worked with the NDDoH to develop inspection and repair measures to detect and prevent emissions from facilities even more effectively going forward. We believe these measures will be included in settlements between the NDDoH and each participating operator. We and the NDDoH, pending Court approval of the settlement, have agreed that we will pay a civil penalty of \$1.2 million, of which \$1.1 million may be reduced by up to 60 percent by early and continued implementation of the aforementioned inspection and repair measures and a quality control policy. We anticipate being able to qualify for all available penalty reductions. The settlement is not an admission by us of any violation.

Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents 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.

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 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

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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. The Court of Appeals for the D.C. Circuit heard oral arguments on the Clean Power Plan in September 2016, but has not yet issued a decision. President Trump has indicated that he is opposed to the Clean Power Plan, and the new administration could withdraw the rule and potentially repropose it, or seek to invalidate the EPA's prior determination that GHGs present an endangerment to public health and the environment. Either action is likely to be challenged in court, which could delay implementation of any new rules.

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 is issuing new 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.

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 James J. Volker, Chairman, President and Chief Executive Officer; Peter W. Hagist, Senior Vice President, Planning; Rick A. Ross, Senior Vice President, Operations; Michael J. Stevens, Senior Vice President and Chief Financial Officer; Mark R. Williams, Senior Vice President, Exploration and Development; Brent P. Jensen, Vice President, Finance and Treasurer; Steven A. Kranker, Vice President, Reservoir Engineering/Acquisitions; or David M. Seery, Vice President, Land, 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.

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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 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 and would not take effect until 12 months after the date of enactment. 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.

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 we could incur interruptions from cyber security attacks, computer viruses or malware. 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 our information systems could lead to data corruption, communication interruption or otherwise significantly disrupt our business operations.

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:

- 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.

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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 736,000 gross (443,800 net) developed and undeveloped acres as of December 31, 2016. Our estimated proved reserves in the Northern Rocky Mountains as of December 31, 2016 were 450.8 MMBOE (63% oil), which represented 73% of our total estimated proved reserves and contributed 108.9 MBOE/d of average daily production in the fourth quarter of 2016.

In April and July 2016, we entered into two separate wellbore participation agreements related to the wells that we drilled in the Williston Basin in 2016, which helped allow us to continue completion activity in this area. As of December 31, 2016, we had four rigs active in the Williston Basin. Across our acreage in the Williston Basin, we have implemented our new completion design which utilizes cemented liners, plug-and-perf technology, significantly higher sand volumes, new diversion technology and both hybrid and slickwater fracture stimulation methods, which has resulted in improved initial production rates.

In order to process the produced gas stream from our wells in the Sanish and Pronghorn fields, we constructed the Robinson Lake gas plant and the Belfield gas plant, respectively. As of December 31, 2016, we held a 50% ownership interest in each of these gas processing plants. On January 1, 2017, we closed on the sale of our interests in these two gas processing plants and the related gathering systems and facilities. Refer to the “Subsequent Events” footnote in the notes to the consolidated financial statements for further information.

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 157,200 gross (132,200 net) developed and undeveloped acres as of December 31, 2016. Our estimated proved reserves in the Central Rocky Mountains as of December 31, 2016 were 160.7 MMBOE (68% oil), which represented 26% of our total estimated proved reserves and contributed 9.2 MBOE/d of average daily production in the fourth quarter of 2016.

We have established production in the Niobrara “A”, “B” and “C” zones and the Codell/Fort Hays formations. Our development plan at Redtail currently includes drilling up to eight wells per spacing unit in the Niobrara “A”, “B” and “C” zones and up to four wells per spacing unit in the Codell/Fort Hays formations. Additionally, the Codell/Fort Hays formation is prospective throughout our acreage in the Redtail field, and we are currently evaluating that formation. We have implemented a new wellbore configuration in this area, which significantly reduces drilling times. As of December 31, 2016, we had one drilling rig operating in the DJ Basin. We suspended completion operations in this area beginning in the second quarter of 2016; however, we plan to resume completion activity in early 2017.

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, 2016, the plant was processing over 16 MMcf/d.

Other

Our other operations primarily relate to non-core assets in Colorado, Mississippi, North Dakota, Texas and Wyoming. As of December 31, 2016, these properties contributed 4.0 MMBOE (90% oil) of proved reserves to our portfolio of operations, which represented 1% of our total estimated proved reserves and contributed 0.8 MBOE/d of average daily production in the fourth quarter of 2016.

In July 2016, we sold our interest in the North Ward Estes field located in Ward and Winkler counties in Texas as further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K.

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Reserves

As of December 31, 2016 and 2015, 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, 2016 and 2015 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, 2016 and 2015, respectively) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
2016				
Proved developed reserves	183,165	51,888	337,860	291,363
Proved undeveloped reserves	211,602	49,605	377,799	324,174
Total proved reserves	394,767	101,493	715,659	615,537
2015				
Proved developed reserves	298,444	55,437	300,631	403,986
Proved undeveloped reserves	298,233	57,510	365,029	416,581
Total proved reserves	596,677	112,947	665,660	820,567

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 76.7 MMBOE in 2016 were primarily attributable to successful drilling in the Williston Basin and DJ Basin. Both the new wells drilled in these areas as well as the PUD locations added as a result of drilling increased our proved reserves.

Sales of minerals in place totaled 114.4 MMBOE during 2016 and were primarily attributable to the disposition of the North Ward Estes Properties as further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K.

In 2016, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 119.8 MMBOE. Included in these revisions were (i) 121.6 MMBOE of downward adjustments caused by lower crude oil, NGL and natural gas prices incorporated into our reserve estimates at December 31, 2016 as compared to December 31, 2015 and (ii) 1.8 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

Proved undeveloped reserves. Our PUD reserves decreased 22% or 92.4 MMBOE on a net basis from December 31, 2015 to December 31, 2016. The following table provides a reconciliation of our PUDs for the year ended December 31, 2016:

	Total (MBOE)
PUD balance—December 31, 2015	416,581
Converted to proved developed through drilling (1)	(14,191)
Added from extensions and discoveries	66,755
Removed due to low commodity prices	(93,260)
Sold	(46,492)
Revisions	(5,219)
PUD balance—December 31, 2016	324,174

(1) During 2016, we incurred \$125 million in capital expenditures on approximately 105 wells which remained uncompleted as of December 31, 2016, and as a result the PUD reserves associated with these wells were not converted to proved developed during 2016.

During 2016, we incurred \$177 million in capital expenditures, or \$12.46 per BOE, to drill and bring on-line 14.2 MMBOE of PUD reserves. In addition, we added 66.8 MMBOE of PUDs from extensions and discoveries during the year primarily due to successful drilling in the Williston Basin and DJ 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.

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

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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, Senior Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer. See 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 Vice President of Reservoir Engineering and Acquisitions is responsible for overseeing the preparation of the reserves estimates. He has over 32 years of experience, the majority of which has involved reservoir engineering and reserve estimation, and he holds a Bachelor’s degree in petroleum engineering from the Colorado School of Mines. He is also a member of the Society of Petroleum Engineers.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by core area at December 31, 2016. 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	696,711	417,473	39,257	26,366	735,968	443,839
Central Rocky Mountains	43,716	37,900	113,462	94,284	157,178	132,184
Other (2)	108,879	61,796	209,681	127,013	318,560	188,809
	849,306	517,169	362,400	247,663	1,211,706	764,832

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- (1) Out of a total of approximately 362,400 gross (247,700 net) undeveloped acres as of December 31, 2016, 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 25% in 2017, 28% in 2018 and 8% in 2019.
- (2) Other includes Arkansas, California, Colorado, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah and Wyoming.

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Production History

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

	Year Ended December 31,		
	2016	2015	2014
Oil production (MMBbl)	34.0	47.2	33.5
NGL production (MMBbl)	6.6	5.5	3.3
Natural gas production (Bcf)	41.4	41.1	30.2
Total production (MMBOE)	47.5	59.6	41.8
Daily production (MBOE/d)	129.9	163.2	114.5
Sanish field production (1)			
Oil production (MMBbl)	7.2	9.4	9.9
NGL production (MMBbl)	1.0	1.2	1.1
Natural gas production (Bcf)	7.8	7.3	5.9
Total production (MMBOE)	9.5	11.8	12.0
North Ward Estes field production (1)			
Oil production (MMBbl)	1.6	3.0	3.1
NGL production (MMBbl)	0.2	0.4	0.4
Natural gas production (Bcf)	0.1	0.2	0.3
Total production (MMBOE)	1.8	3.4	3.6
Average sales prices (before the effects of hedging):			
Oil (per Bbl)	\$ 34.36	\$ 40.95	\$ 81.50
NGLs (per Bbl)	\$ 8.88	\$ 12.67	\$ 39.17
Natural gas (per Mcf)	\$ 1.40	\$ 2.20	\$ 5.53
Average production costs:			
Production costs (per BOE) (2)	\$ 8.25	\$ 9.02	\$ 11.24

- (1) The Sanish and North Ward Estes fields were our only fields that contained 15% or more of our total proved reserve volumes during the periods presented. In July 2016, we sold our interest in the North Ward Estes field.
- (2) Production costs reported above exclude from lease operating expenses ad valorem taxes of \$3 million (\$0.06 per BOE), \$18 million (\$0.30 per BOE) and \$27 million (\$0.65 per BOE) for the years ended December 31, 2016, 2015 and 2014, respectively.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by core area at December 31, 2016. 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	2,804	1,250	-	-	2,804	1,250
Central Rocky Mountains	280	200	-	-	280	200
Other (2)	1,492	424	111	43	1,603	467
Total	4,576	1,874	111	43	4,687	1,917

(1) 12 wells have multiple completions. These 12 wells contain a total of 30 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, Mississippi, 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

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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.