

WHITING PETROLEUM CORP
Form 10-K
February 28, 2014

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, 2013

or

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

For the transition period from _____ to _____

Commission file number: 001-31899

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

Delaware
(State or other jurisdiction
of incorporation or organization)

20-0098515
(I.R.S. Employer
Identification No.)

1700 Broadway, Suite 2300
Denver, Colorado
(Address of principal executive offices)

80290-2300
(Zip code)

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

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

Common Stock, \$0.001 par value
Preferred Share Purchase Rights

(Title of Class)

New York Stock Exchange
New York Stock Exchange
(Name of each exchange on which
registered)

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

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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

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 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

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, 2013: \$5,481,981,242.

Number of shares of the registrant's common stock outstanding at February 14, 2014: 118,956,489 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2014 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.

“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 of 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.

“CO₂ flood” A tertiary recovery method in which CO₂ is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

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

“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.

“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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

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

“FASB” Financial Accounting Standards Board.

“FASB ASC” The Financial Accounting Standards Board Accounting Standards Codification.

“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 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 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 of natural gas.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet of natural gas.

“MMcf/d” One MMcf per day.

“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 perforations in 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 many states require plugging of abandoned

wells.

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“possible reserves” Those reserves that are less certain to be recovered than probable reserves.

“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.

“probable reserves” Those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“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.

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“proved undeveloped reserves” 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 schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for 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.

“PUD” Proved undeveloped reserves.

“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.

“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” Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

“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.

“service well” A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or

flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for in-situ combustion.

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“standardized measure of discounted future net cash flows” 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 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 exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. We were incorporated in 2003 in connection with our initial public offering.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2013, our estimated proved reserves totaled 438.5 MMBOE, representing a 16% increase in our proved reserves since December 31, 2012. Our 2013 average daily production was 94.1 MBOE/d and results in an average reserve life of approximately 12.8 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2013, their corresponding pre-tax PV10% values, and our fourth quarter 2013 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2013:

Core Area	Proved Reserves (1)					Pre-Tax PV10% Value (2)	4th Quarter 2013 Average Daily Production (MBOE/d)
	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	(in millions)	
Rocky Mountains	236.6	25.7	208.8	297.0	80%	\$ 7,309.7	84.7
Permian Basin	106.4	17.8	17.6	127.1	84%	1,524.6	12.3
Other (3)	4.4	1.4	51.1	14.4	31%	159.7	4.0
Total	347.4	44.9	277.5	438.5	79%	\$ 8,994.0	101.0
Discounted Future Income Taxes						(2,400.1)	
Standardized Measure of Discounted Future Net Cash Flows						\$ 6,593.9	

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2013, pursuant to 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, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income

taxes. We believe pre-tax PV10% is a useful measure for investors for 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 standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

- (3) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

While historically we have grown through acquisitions, we are increasingly focused on a balance between our exploration and development programs and are continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities.

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Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- allocating a portion of our exploration and development (“E&D”) budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas.

During 2013, we incurred \$2,896.1 million in exploration, development and cash acquisition capital expenditures, including \$2,398.4 million for the drilling of 428 gross (229.2 net) wells. Of these new wells, 220.7 (net) resulted in productive completions and 8.5 (net) were unsuccessful, yielding a 96% success rate.

Our current 2014 E&D budget is \$2.7 billion, and included in this amount is approximately \$116.0 million in acreage acquisition costs. The 2014 budget of \$2.7 billion represents a slight increase from the \$2,675.2 million in E&D (which consisted of exploration, development and acreage expenditures) we incurred in 2013. We expect to fund substantially all of our 2014 E&D budget using net cash provided by operating activities, cash on hand and borrowings under our credit facility.

We continually evaluate our current 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.

Acquisitions and Divestitures

The following is a summary of our acquisitions and divestitures during the last two years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this Annual Report on Form 10-K for more information on these acquisitions and divestitures.

2013 Acquisitions. On September 20, 2013, we completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of \$260.0 million.

2013 Divestitures. On October 31, 2013, we completed the sale of approximately 45,000 gross (32,200 net) acres, including our interests in certain producing oil and gas wells and undeveloped acreage, in our Big Tex prospect located in the Delaware Basin for a cash purchase price of \$152.0 million (subject to post-closing adjustments), resulting in a pre-tax gain on sale of \$13.0 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas. The producing properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2012, representing 0.3% of our proved reserves as of that date, and generated 0.2 MBOE/d of our third quarter 2013 average daily net production.

On July 15, 2013, we completed the sale of our interests in certain oil and gas producing properties located in our enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, our entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the “Postle Properties”) for a cash purchase price of \$809.7 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of \$109.7 million. We used the net proceeds from this sale to repay a portion of the debt outstanding under our credit agreement. The Postle Properties consisted of estimated proved reserves of 45.1

MMBOE as of December 31, 2012, representing 11.9% of our proved reserves as of that date, and generated 8% (or 7.6 MBOE/d) of our June 2013 average daily net production.

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2012 Acquisitions. On March 22, 2012, we completed the acquisition of approximately 13,300 net undeveloped acres in the Missouri Breaks field in Richland County, Montana for \$33.3 million.

2012 Divestitures. On May 18, 2012, we sold a 50% ownership interest in our Belfield gas processing plant, natural gas gathering system, oil gathering system and related facilities located in Stark County, North Dakota for total cash proceeds of \$66.2 million. We used the net proceeds from the sale to repay a portion of the debt outstanding under our credit agreement.

On March 28, 2012, we completed an initial public offering of units of beneficial interest in Whiting USA Trust II (“Trust II”), selling 18,400,000 Trust II units at \$20.00 per unit, which generated net proceeds of \$322.3 million after underwriters’ fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of \$128.2 million. Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to Trust II in exchange for 100% of the trust’s units issued, or 18,400,000 units.

The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II’s right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest. The conveyance of the net profits interest to Trust II consisted entirely of proved reserves of 10.61 MMBOE as of the January 1, 2012 effective date, representing 3% of our proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of our March 2012 average daily net production.

Business Strategy

Our goal is to generate meaningful growth in our net asset value per share of proved reserves through the exploration, development and acquisition of oil and gas projects with attractive rates of return on capital employed. To date, we have pursued this goal through both continued field development in our core areas and the acquisition of reserves. Because of our extensive property base, we are pursuing several economically attractive oil and gas opportunities to develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin project has become one of our central objectives. As of December 31, 2013, we have assembled approximately 1,147,500 gross (715,000 net) developed and undeveloped acres in the Williston Basin located in Montana and North Dakota. As of December 31, 2013, we had 18 drilling rigs operating in the Williston Basin. During 2013, the focus of our development in the Williston Basin continued in the Sanish, Lewis & Clark/Pronghorn, Hidden Bench/Tarpon, Missouri Breaks and Cassandra fields. Additionally, Whiting owns a 50% ownership interest in two gas processing plants located in the Williston Basin. The Robinson Lake plant located in our Sanish field has a current processing capacity of approximately 90 MMcf/d, and we have projects underway to increase this processing capability to 110 MMcf/d by mid-year 2014. Our Belfield Plant located near the Pronghorn field has a processing capacity of 35 MMcf/d. Both plants have fractionation capability to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices.

A new area of focus for us is our Redtail field in the Denver Julesberg Basin (“DJ Basin”) in Weld County, Colorado, where we have the potential to drill over 1,000 gross wells targeting several intervals in the Niobrara formation. As of December 31, 2013, we had approximately 169,700 gross (122,300 net) acres, with three drilling rigs operating in this area. We are nearing the completion of a gas processing plant in Weld County, Colorado with an initial processing

capacity of 15 MMcf/d, which will process production from our Redtail field. We expect our Redtail field will be another growth platform for Whiting in 2014 and beyond.

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Developing Existing Properties. Our current property base, which includes our acquisitions over the past ten years, provides us with numerous low-risk opportunities for exploration and development drilling. As of December 31, 2013, we have identified a drilling inventory of over 3,200 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists of the development of our proved and unproved reserves. Additionally, we have opportunities to apply and expand enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. In 2005, we acquired the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced significant production increases in this field through the use of secondary and tertiary recovery techniques, and we anticipate such production increases will continue over the next five to seven years. In this field, we are actively injecting water and CO₂ and executing extensive re-development, drilling and completion operations, as well as expanding our gas processing facilities, which will allow us to separate and inject approximately 295 MMcf/d of recycled CO₂, thereby maximizing our recovery of oil and gas from this reservoir.

Growing Through Accretive Acquisitions. From 2004 to 2013, we completed 17 separate significant acquisitions of producing properties for estimated proved reserves of 248.0 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 then effectively managing properties we acquire. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings, internally generated cash flow and certain oil and gas divestitures, as appropriate, to maintain our strong financial position. 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, as we did with the sale of our Postle Properties, which we completed on July 15, 2013. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and fixed price gas contracts to provide an attractive base commodity price level.

Competitive Strengths

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

Balanced, Long-Lived Asset Base. As of December 31, 2013, we had interests in 10,476 gross (3,922 net) productive wells across approximately 1,387,200 gross (751,700 net) developed acres across all our geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and developing properties in these areas, presents us with multiple opportunities to execute our strategy. Our proved reserve life is approximately 12.8 years based on year-end 2013 proved reserves and 2013 production.

Experienced Management Team. Our management team averages 28 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, each of our acquisition professionals has at least 29 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. Our technical team has access to approximately 12,100 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. We have a team of 10 professionals averaging over 25 years of experience managing CO₂ floods, which provides us with the ability to pursue other CO₂ flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

In 2011, we completed the build-out and installation of an in-house, state-of-the-art rock analysis laboratory. We continue to utilize the data from this rock lab to support real-time drilling and completion decisions. In addition, it has helped us to further understand unconventional oil plays, which has given us the confidence to assemble over 600,000 gross acres in three new oil resource plays, located in three separate basin areas that are new to us.

During 2013, we tested several different modifications to our completion techniques, including varying the number of completion stages, utilizing different fracture stimulation fluids and increasing the volume of sand and ceramic proppant used in these fluids. As we continued to refine our process, our well completions in several of our development areas have evolved to utilize cemented liners and plug-and-perf technology to deliver improved results. In 2014, we plan to utilize this technique on a majority of the wells we drill in the Williston Basin. We have also tested this completion technique in the Niobrara formation in the DJ Basin of Colorado and the Delaware Basin of West Texas with encouraging results. We continue to refine our completion techniques to deliver improved results across all of our fields.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2013 are summarized 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
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	Proved	(in millions)
Rocky Mountains:						
PDP	128.5	13.2	122.1	161.9	55 %	
PDNP	0.5	0.1	1.2	0.8	- %	
PUD	107.6	12.4	85.5	134.3	45 %	
Total proved	236.6	25.7	208.8	297.0	100 %	\$ 2,597.7
Total probable	90.8	17.4	215.3	144.1		\$ 2,835.7
Total possible	59.0	8.4	136.2	90.1		\$ 1,866.2
Permian Basin:						
PDP	49.6	5.9	11.8	57.4	45 %	
PDNP	15.3	3.5	2.8	19.3	15 %	
PUD	41.5	8.4	3.0	50.4	40 %	
Total proved	106.4	17.8	17.6	127.1	100 %	\$ 1,335.3
Total probable	15.9	4.3	34.6	26.0		\$ 265.1
Total possible	76.9	16.1	2.8	93.4		\$ 739.8
Other (1):						
PDP	3.6	0.8	38.7	11.0	76 %	
PDNP	0.7	0.3	6.6	2.1	15 %	
PUD	0.1	0.3	5.8	1.3	9 %	
Total proved	4.4	1.4	51.1	14.4	100 %	\$ 21.4
Total probable	2.6	0.6	17.7	6.1		\$ 57.1
Total possible	1.3	0.1	24.8	5.6		\$ 80.1
Total Company:						
PDP	181.7	19.9	172.6	230.3	53 %	
PDNP	16.5	3.9	10.6	22.2	5 %	
PUD	149.2	21.1	94.3	186.0	42 %	
Total proved	347.4	44.9	277.5	438.5	100 %	\$ 3,954.4
Total probable	109.3	22.3	267.6	176.2		\$ 3,157.9
Total possible	137.2	24.6	163.8	189.1		\$ 2,686.1

(1) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

The estimated future capital expenditures in the table above 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.

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 to storage facilities. The table below presents percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2013, 2012 and 2011. 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.

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	2013	2012	2011
Plains Marketing LP	21%	20%	27%
Shell Trading US	14%	14%	13%
Eighty Eight Oil Company	11%	11%	8%
Bridger Trading LLC	8%	11%	6%

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured 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

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained 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 financial or personnel resources permit. 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. Also, there is substantial competition for available investment capital in the oil and gas industry.

Regulation

Regulation of Transportation, Sale and Gathering of Natural Gas

The Federal Energy Regulatory Commission (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 and all sales of crude oil, condensate and NGLs 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.

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The FERC implemented 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. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. 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 recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Transportation and safety of natural gas is subject to regulation by the Department of Transportation (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 the Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency within the DOT, 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. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls 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 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 2.65% adjustment, for the five-year period July 1, 2011 through June 30, 2016. This represents an increase for the PPI-FG plus 1.3% adjustment from the prior five-year period. A requested rehearing of the order was denied by the FERC. 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.

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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 has exercised this authority over a specific pipeline in February 2014 in response to significant disruptions in the supply of propane. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Transportation and safety of oil and hazardous liquid is subject to regulation by the DOT under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. PHMSA 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.

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.

Some of our offshore operations are conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the "BOEM"). Currently, only 0.1% of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was \$32.8 million as of December 31, 2013. Whiting is therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act. 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. Under limited circumstances, the BOEM could require us to suspend or terminate our operations on a federal lease.

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.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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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.

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 or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may be regulated as “hazardous substances.” Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which 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 was 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, the offsite disposal facilities, and the substances disposed or released on them may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

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- 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 \$350.0 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus \$75.0 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 \$35.0 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 \$150.0 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 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 waters 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 but, to date, the agency has not taken any action on the petition. The EPA has not formally responded to this petition yet. 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.

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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 (“SPCC”) 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.

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 water, sand and 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, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the EPA recently issued guidance, which was published in the Federal Register on February 12, 2014, for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

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At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release a draft final report for public comment and peer review in 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards for coalbed methane in 2013 and shale gas in 2014 that such wastewater must meet before being transported to a treatment plant. 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. The U.S. Department of the Interior released a draft proposed rule in May 2012 governing hydraulic fracturing on federal and Indian oil and natural gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing and monitoring of well-stimulation operations, and on May 24, 2013 the Federal Bureau of Land Management issued a revised draft of the proposed rule. On November 20, 2013, the U.S. House of Representatives passed the Protecting States' Rights to Promote American Energy Security Act, which would ban the U.S. Department of the Interior from regulating hydraulic fracturing if enacted into law. 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 restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, on June 17, 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 permit 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 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.

Global Warming and Climate Change. On December 15, 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 begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the CAA, including one rule that limits 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 on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("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 with reporting beginning in 2012 for emissions occurring in 2011. We believe that we are in compliance with all substantial applicable emissions requirements, and we are preparing to comply with future requirements.

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In addition, both houses of Congress have 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, greenhouse gas 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 and natural gas that we produce. Finally, it should be noted that some 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 December 31, 2013, we had 958 full-time employees, including 39 senior level geoscientists and 73 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 Securities and Exchange Commission.

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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. If any of the following risks develop into actual events, 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. These factors include, but are not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- 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 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;
- the level of global oil and natural gas inventories;
- developments of United States energy infrastructure, such as the approval to proceed with the Keystone XL pipeline from Hardisty, Alberta to Cushing, Oklahoma and the development of liquefied natural gas exporting facilities and the perceived timing thereof;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- 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.

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis but also may ultimately reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve quantities. A substantial or extended decline in oil, NGL or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, 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 or borrow any such shortfall. Lower oil, NGL and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the 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.

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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 production 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:

- delays imposed by or resulting from compliance with regulatory requirements;
- delays 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, completion services and CO₂;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil, NGL and natural gas prices;
- pipeline takeaway and refining and processing capacity; and
- title problems.

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 water, sand and 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, Michigan, Montana, North Dakota and Texas, 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”) recently issued guidance, which was published in the Federal Register on February 12, 2014, for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

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At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release a draft final report for public comment and peer review in 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards for coalbed methane in 2013 and shale gas in 2014 that such wastewater must meet before being transported to a treatment plant. 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. The U.S. Department of the Interior released a draft proposed rule in May 2012 governing hydraulic fracturing on federal and Indian oil and natural gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing and monitoring of well-stimulation operations, and on May 24, 2013 the Federal Bureau of Land Management issued a revised draft of the proposed rule. On November 20, 2013, the U.S. House of Representatives passed the Protecting States' Rights to Promote American Energy Security Act, which would ban the U.S. Department of the Interior from regulating hydraulic fracturing if enacted into law. 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 restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, on June 17, 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 permit 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 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.

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

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO₂ into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO₂ injection as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO₂. Under our CO₂ contracts, if the supplier suffers an inability to

deliver its contractually required quantities of CO₂ to us and other parties with whom it has CO₂ contracts, then the supplier may reduce the amount of CO₂ on a pro rata basis it provides to us and such other parties. If this occurs or if we are otherwise limited in the quantities of CO₂ available to us, we may not have sufficient CO₂ to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes could be negatively impacted. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO₂ as part of our enhanced recovery techniques.

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The development of the proved undeveloped reserves in the North Ward Estes field may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2013, proved undeveloped reserves comprised 39% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of \$684.2 million at the North Ward Estes field as of December 31, 2013. This field encompasses 20% of our total estimated future development costs related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO₂ injection installations, the success of which is less predictable than traditional development techniques.

Prospects that we decide to drill may not yield oil or gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Annual Report on Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

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 \$220.8 million impairment write-down during 2013 for the partial impairment of producing properties, primarily natural gas, in Michigan, Utah and Wyoming. 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.

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.

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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. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by \$0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2013 would have decreased from \$6,593.9 million to \$6,583.2 million. If oil prices 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, 2013 would have decreased from \$6,593.9 million to \$6,483.8 million.

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 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. In addition, curtailments or damage to pipelines 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, there have been recent accidents involving rail cars carrying Bakken formation crude oil, which resulted in the U.S. Department of Transportation (the “DOT”) issuing an emergency order on February 25, 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. An accident involving rail cars could result in significant personal injuries and property and environmental damage. Additionally, added regulations in response to such accidents could result in additional costs that could increase transportation expenses.

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 soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

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, 2013, we had no borrowings and \$3.0 million in letters of credit outstanding under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit facility with \$1,197.0 million of available borrowing capacity, as well as \$2,300.0 million of senior notes outstanding and \$350.0 million of 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 our senior subordinated notes and Whiting Oil and Gas' credit agreement.

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Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- 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; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement is subject to certain rate variability.

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 periodically redetermined based on an evaluation of our oil and gas reserves. 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, 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.

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 our senior subordinated 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:

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- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our senior or subordinated 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, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. Also, the indentures under which we issued our senior notes and our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of 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 our senior subordinated notes or Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

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 and oil and gas property divestments. We intend to finance future capital expenditures with cash flow from operations, cash on hand and existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- 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 decreases 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.

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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.

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 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; and
- we may issue additional equity or debt securities in order to fund future acquisitions.

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.

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 and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. 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, crews and associated supplies, equipment and services. Additionally, our operations in some instances require supply materials for production, such as CO₂, which could become subject to shortage and increasing costs. Shortages of field personnel, drilling rigs, equipment, supplies or personnel or price increases could delay or adversely affect our exploration and

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

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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. As of December 31, 2013, we had identified a drilling inventory of over 3,200 gross drilling locations. 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.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and 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 the fourth quarter of 2013, we recorded a \$13.6 million non-cash charge for the impairment of unproved properties in our Flat Rock field in Utah. 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 2013, we completed 17 separate significant acquisitions of producing properties with a combined purchase price of \$2,160.3 million for estimated proved reserves as of the effective dates of the acquisitions of 248.0 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.

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

We may not be able to replace the reserves on properties we divest, and the agreements pursuant to which assets we divest may contain continuing indemnification obligations.

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. 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 credit risk and 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, placed with major financial institutions. As of February 6, 2014, we had contracts, which include our 10% share of the Whiting USA Trust II hedges, covering the sale of between 1,204,250 and 1,284,250 barrels of oil per month for all of 2014. All of our oil hedges will expire by December 2014. 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.

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

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. 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.

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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 77% of our net productive oil and natural gas wells, which represents 86% of our proved developed producing reserves as of December 31, 2013. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of our properties. The failure

of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in 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 commercially reasonable efforts to cause the operator to act as a reasonably prudent operator, we are limited in our ability to do so.

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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 in 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;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

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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.

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.

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 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. 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.

On December 15, 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 begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the Federal Clean Air Act (the “CAA”), including one rule that limits 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 on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“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 with reporting beginning in 2012 for emissions occurring in 2011.

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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, greenhouse gas 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 some 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 generally are 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 and Chief Executive Officer; James T. Brown, President and Chief Operating Officer; Mark R. Williams, Senior Vice President, Exploration and Development; Steven A. Kranker, Vice President, Reservoir Engineering/Acquisitions; Rick A. Ross, Vice President, Operations; David M. Seery, Vice President, Land; Michael J. Stevens, Vice President and Chief Financial Officer; or Peter W. Hagist, Vice President, Permian Operations, 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.

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, marketing oil and gas and securing trained 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 financial or personnel 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. Also, there is substantial competition for available capital for investment in the oil and gas industry. 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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Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or deferred as a result of future legislation.

In April 2013, President Obama's Administration released its proposed federal budget for fiscal year 2014 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

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

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations forthcoming 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, will be established through rulemakings and will 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.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

Summary of Oil and Gas Properties and Projects

Rocky Mountains Region

Our Rocky Mountains operations include assets in the states of North Dakota, Colorado, Montana, Wyoming, Utah and California. As of December 31, 2013, our estimated proved reserves in the Rocky Mountains region were 297.0 MMBOE (80% oil), which represented 68% of our total estimated proved reserves and contributed 84.7 MBOE/d of average daily production in the fourth quarter of 2013.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations and encompass approximately 174,700 gross (82,400 net) developed and undeveloped acres. Net production in the Sanish and Parshall fields averaged 40.4 MBOE/d for the fourth quarter of 2013, representing a 10% increase from 36.8 MBOE/d in the third quarter of 2013. As of December 31, 2013, we had four drilling rigs active in the Sanish field. We also initiated three high density pilot programs in the Sanish field and participated in several infill wells in the Parshall field during 2013. We recently completed two infill wells using our new completion design and are encouraged by the initial results.

In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake gas plant. The plant has a current processing capacity of 90 MMcf/d and fractionation equipment that allows us to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices. We currently have projects underway to expand the inlet compression and processing capability at this plant to 110 MMcf/d.

Lewis & Clark/Pronghorn Fields. Our Lewis & Clark/Pronghorn fields are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). As of December 31, 2013, the Lewis & Clark/Pronghorn fields encompassed approximately 392,500 gross (263,400 net) developed and undeveloped acres. Net production in the Lewis & Clark/Pronghorn fields averaged 15.1 MBOE/d in the fourth quarter of 2013, representing a 6% increase from 14.2 MBOE/d in the third quarter of 2013. As of December 31, 2013, we had four drilling rigs operating in the Pronghorn field, all of which are utilizing drilling pads, with two or three wells from each pad. Additionally, we have tested our new completion design in the Pronghorn field utilizing cemented liners and plug-and-perf technology and are encouraged by the results. As a result of these successes, we plan to use this completion technique on all future wells drilled in the area.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 35 MMcf/d and which primarily processes production from the Pronghorn area. In November 2012, we began connecting other operators' wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. Currently, there is inlet compression in place to process 35 MMcf/d, and as of December 31, 2013 the plant was processing 18 MMcf/d. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and continue to operate the Belfield plant and facilities.

Hidden Bench/Tarpon Fields. Our Hidden Bench and Tarpon fields in McKenzie County, North Dakota target the Bakken and Three Forks formations and encompass approximately 66,800 gross (37,400 net) developed and undeveloped acres and 8,800 gross (6,300 net) developed and undeveloped acres, respectively, as of December 31, 2013. Net production at Hidden Bench/Tarpon averaged 13.4 MBOE/d in the fourth quarter of 2013, which

represents a 31% increase from 10.2 MBOE/d in the third quarter of 2013. We have also implemented our new completion design at our Hidden Bench field, utilizing cemented liners and plug-and-perf technology, which has generated positive results. In addition, we have tested a high density drilling pilot at our Hidden Bench field and are currently analyzing the resulting data. In the Tarpon field, we have drilled six productive wells as of December 31, 2013. We had previously planned to drill most of the remaining Tarpon development wells during 2013 but have experienced delays resulting from the U.S. Forest Service's requirement to perform an Environmental Assessment prior to the issuance of federal drilling permits for these wells. We anticipate that we will be able to resume drilling in 2014, and we have begun permitting additional wells for 2014.

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Missouri Breaks Field. As of December 31, 2013, we had approximately 98,600 gross (64,300 net) developed and undeveloped acres at our Missouri Breaks field located in Richland County, Montana and McKenzie County, North Dakota. In the fourth quarter of 2013, net production from the Missouri Breaks field averaged 3.8 MBOE/d, representing a 31% increase from 2.9 MBOE/d in the third quarter of 2013. During 2013, we implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and the new design has improved initial production rates. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Redtail Field. Our Redtail field in the Weld County, Colorado portion of the DJ Basin targets the Niobrara formation and encompasses approximately 169,700 gross (122,300 net) developed and undeveloped acres as of December 31, 2013. In September 2013, we completed the acquisition of approximately 47,800 gross (32,100 net) acres at our Redtail field, including interests in one producing well. Our development plan at Redtail currently includes drilling up to eight Niobrara "B" wells per spacing unit and eight Niobrara "A" wells per spacing unit. In 2014, we plan to test a high-density pattern in the Niobrara "A", "B" and "C" zones drilling 32 wells per spacing unit. As of December 31, 2013, we had three drilling rigs operating in this area, and we plan to add another rig in 2014. We implemented a new completion design in this field utilizing larger proppant volumes, which has been yielding improved production results, and we are currently evaluating the use of cemented liners in the Redtail field.

The associated gas produced with the Niobrara oil must be processed before being sold, and we are nearing completion of the construction of a gas processing plant for this area. The plant's initial inlet capacity will be 15 MMcf/d, and we plan to further expand the plant's capacity to 60 MMcf/d in 2015. We anticipate having the plant online in early 2014.

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2013, the Permian Basin region contributed 127.1 MMBOE (84% oil) of estimated proved reserves to our portfolio of operations, which represented 29% of our total estimated proved reserves and contributed 12.3 MBOE/d of average daily production in the fourth quarter of 2013.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interests in approximately 62,300 gross (60,500 net) developed and undeveloped acres in Ward and Winkler counties, Texas. Current production from our enhanced oil recovery ("EOR") project is from the Yates formation at 2,600 feet, which is the primary producing zone, with additional production from other zones including the Queen at 3,000 feet.

The North Ward Estes field has been responding positively to the water and CO₂ floods that we initiated in May 2007. We are currently injecting CO₂ in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO₂ flood are continuing to respond. In the fourth quarter of 2013, production from the field averaged 9.8 MBOE/d, which represents a 2% increase from 9.6 MBOE/d in the third quarter of 2013. As of December 31, 2013, we were injecting approximately 390 MMcf/d of CO₂ in this field, over half of which is recycled.

North Ward Estes' proved reserves at December 31, 2013 were 39% proved undeveloped. In order to fully develop the reserves at this field within our currently planned timeframe, we will need to utilize significant quantities of purchased CO₂. As of December 31, 2013, we currently have under contract 100% of the future CO₂ volumes that we believe are necessary to develop the field's PUDs. In addition, we are currently in negotiations and planning for future sources of CO₂ capable of generating sufficient quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, we cannot provide absolute assurance with respect to the timing or actual quantities of CO₂ that will be obtainable for the development of this field's oil and gas reserves.

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Big Tex Prospect. As of December 31, 2013, we had accumulated approximately 52,300 gross (40,900 net) developed and undeveloped acres at our Big Tex prospect in Pecos, Reeves and Ward counties, Texas in the Delaware Basin. Prospective formations include the Brushy Canyon, Bone Spring and Wolfcamp horizons. In October 2013, we sold approximately 45,000 gross (32,200 net) acres, including interests in certain producing oil and gas wells, as well as undeveloped acreage, in our Big Tex prospect. Refer to “Acquisitions and Divestitures” in Item 1 of this Annual Report on Form 10-K for more information on this divestiture.

Other

Our other operations primarily relate to assets in Arkansas, Louisiana, Michigan, Oklahoma and Texas. As of December 31, 2013, these properties contributed 14.4 MMBOE (31% oil) of proved reserves to our portfolio of operations, which represented 3% of our total estimated proved reserves and contributed 4.0 MBOE/d of average daily production in the fourth quarter of 2013. In Michigan, we also operate the West Branch and Reno gas processing plants. The West Branch plant gathers production from the Clayton unit, West Branch field and other smaller fields.

Reserves

As of December 31, 2013, all of our oil and gas reserves are attributable to properties within the United States. A summary of our oil and gas reserves as of December 31, 2013 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, 2013) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Developed	198,204	23,721	183,129	252,446
Undeveloped	149,217	21,148	94,385	186,096
Total proved—December 31, 2013	347,421	44,869	277,514	438,542
Probable reserves				
Developed	748	139	6,832	2,026
Undeveloped	108,520	22,191	260,723	174,165
Total probable—December 31, 2013	109,268	22,330	267,555	176,191
Possible reserves				
Developed	1,989	387	1,746	2,667
Undeveloped	135,234	24,220	162,034	186,460
Total possible—December 31, 2013	137,223	24,607	163,780	189,127

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.

In 2013, total extensions and discoveries of 108.8 MMBOE were primarily attributable to successful drilling in our Redtail, Sanish, Missouri Breaks, Hidden Bench and Pronghorn fields. The new wells drilled in these areas and their related PUD locations added during the year increased our proved reserves.

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In 2013, total sales of minerals in place of 43.8 MMBOE were primarily attributable to the disposition of the Postle Properties, further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, which decreased our proved reserves.

In 2013, total purchases of minerals in place of 17.1 MMBOE were primarily attributable to the acquisition of 121 producing oil and gas wells and undeveloped acreage in the Williston Basin, further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, which increased our proved reserves.

In 2013, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 12.0 MMBOE. Included in these revisions were (i) 4.9 MMBOE of upward adjustments caused by higher crude oil and natural gas prices incorporated into our reserve estimates at December 31, 2013 as compared to December 31, 2012 and (ii) 7.1 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

Proved undeveloped reserves. Our PUD reserves increased 36% or 49.2 MMBOE on a net basis from December 31, 2012 to December 31, 2013. The following table provides a reconciliation of our PUDs for the year ended December 31, 2013:

	Total (MBOE)
PUD balance—December 31, 2012	136,896
Converted to proved developed through drilling (1)(3)	(27,782)
Converted to proved developed at EOR projects (2)(3)	(12,364)
Added from revisions, extensions and discoveries	90,519
Removed for five-year rule	(602)
Removed due to low commodity prices	(143)
Purchased	12,745
Sold	(13,173)
PUD balance—December 31, 2013	186,096

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- (1) We incurred \$701.5 million in capital expenditures, or \$25.25 per BOE, to drill and bring on-line these PUD quantities.
 - (2) Amount relates to PUD volumes that became proved developed reserves during 2013 at our CO₂ EOR project in the North Ward Estes field, at a cost of \$40.35 per BOE.
 - (3) Combining the PUD drilling conversions with the PUD EOR conversions, we converted PUDs to proved developed reserves at a cost of \$29.90 per BOE during 2013.

During the year we added 90.5 MMBOE of gross PUD volumes, and this increase in proved undeveloped reserves was primarily due to additional PUD locations added based on successful drilling in the Northern and Central Rockies areas and additional PUD reserves being assigned to our North Ward Estes EOR project.

Based on our 2013 year end independent engineering reserve report, we will drill all of our individual PUD drilling locations within five years. However, we do have certain quantities of proved undeveloped reserves in the North Ward Estes field that will remain in the PUD category for periods extending beyond five years because of certain external factors that preclude the development of the North Ward Estes enhanced oil recovery PUDs all at once. Due to the large areal extent of the field, the CO₂ EOR project will progress through the field in a sequential manner as earlier injection areas are completed and new injection areas are initiated. External factors that preclude the initiation of the CO₂ project throughout the field at the same time include: (i) the volume of injection water necessary to

re-pressure the reservoir in advance of the CO₂ injection, (ii) the volume of purchased and recycled CO₂ necessary to be injected to process the oil in the reservoir, and (iii) the equipment and manpower necessary to build the infrastructure and prepare the wells for the EOR project. Our staged development plan is designed to expand the project as quickly and efficiently as possible to fully develop the field.

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Probable reserves. Estimates of probable developed and undeveloped reserves are inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that is as likely as not to be achieved. Estimates of probable reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain and even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserve estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Increases in probable reserves during 2013 were primarily attributable to 724 new probable well locations that were added in 2013 as a result of our drilling activity across the Rocky Mountains region. During 2013, 31.3 MMBOE of probable reserves were converted to proved reserves at our North Ward Estes field, our Redtail field and various fields in the Northern Rocky Mountains.

Possible reserves. Estimates of possible developed and undeveloped reserves are also inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate possible reserve quantities, and when deterministic methods are used to estimate possible reserve quantities, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and we believe that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Possible reserves increased during 2013 primarily due to successful drilling at our Redtail, Sanish, Parshall, Lewis & Clark/Pronghorn and Hidden Bench fields. During 2013, 27.0 MMBOE of possible reserves were converted to probable at our Redtail field and various other fields in the Northern Rocky Mountains, and 19.7 MMBOE of possible reserves were converted to proved at certain fields in the Northern Rocky Mountains.

At December 31, 2013, our probable reserves were estimated to be 176.2 MMBOE and our possible reserves were estimated to be 189.1 MMBOE, for a total of 365.3 MMBOE. The EOR project at our North Ward Estes field

represented 94.1 MMBOE, or 26%, of our total 365.3 MMBOE probable and possible reserve quantities. In order to fully develop the EOR probable and possible reserves at North Ward Estes, we will need to utilize significant quantities of purchased CO₂. We are currently in negotiations and planning for future sources capable of generating sufficient CO₂ quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO₂ supplies is subject to uncertainty and may require significant future capital expenditures by us, and we cannot therefore provide assurance with respect to the timing or actual quantities of CO₂ that will be obtainable for the development of such reserves.

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Preparation of reserves estimates. We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and their own set of 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 (1992) 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 and Midland offices to review field performance and future development plans. Following these reviews, 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. Robert D. Ravnaas, President. Mr. Ravnaas 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. Ravnaas.

Our Vice President of Reservoir Engineering and Acquisitions is responsible for overseeing the preparation of the reserves estimates. He has over 29 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.

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Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2013. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross(2)	Net(2)	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	61,579	42,555	179,242	116,629	240,821	159,184
Louisiana	40,074	11,691	101,325	90,862	141,399	102,553
Michigan	139,351	61,064	291,960	247,996	431,311	309,060
Montana	91,973	55,425	136,964	81,730	228,937	137,155
New Mexico	16,665	5,427	78,190	56,668	94,855	62,095
North Dakota	553,050	316,872	365,538	261,008	918,588	577,880
Oklahoma	56,645	28,392	406	68	57,051	28,460
Texas	260,935	147,963	84,214	60,849	345,149	208,812
Utah	35,826	18,370	406,522	240,108	442,348	258,478
Wyoming	95,725	55,835	49,312	36,072	145,037	91,907
Other (1)	9,810	4,503	912	434	10,722	4,937
Total	1,387,181	751,703	1,694,585	1,192,424	3,081,766	1,944,127

(1) Other includes Alabama, Arkansas, Kansas, Mississippi and Nebraska.

(2) Out of a total of approximately 1,694,585 gross (1,192,424 net) undeveloped acres as of December 31, 2013, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 13% in 2014, 27% in 2015 and 22% in 2016.

Production History

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

	Year Ended December 31,		
	2013	2012	2011
Oil production (MMBbl)	27.0	23.1	18.3
NGL production (MMBbl)	2.8	2.8	2.1
Natural gas production (Bcf)	26.9	25.8	26.4
Total production (MMBOE)	34.3	30.2	24.8
Daily production (MBOE/d)	94.1	82.5	67.9
North Ward Estes field production (1)			
Oil production (MMBbl)	2.9	2.8	2.6
NGL production (MMBbl)	0.4	0.3	0.4
Natural gas production (Bcf)	0.3	0.3	0.4
Total production (MMBOE)	3.4	3.2	3.0
Sanish field production (1)			
Oil production (MMBbl)	9.8	9.0	6.5
NGL production (MMBbl)	1.1	1.2	0.8
Natural gas production (Bcf)	4.8	3.6	2.2
Total production (MMBOE)	11.7	10.8	7.7

Average sales prices (before the effects of hedging):

Oil (per Bbl)	\$ 90.39	\$ 83.86	\$ 88.61
NGLs (per Bbl)	\$ 40.41	\$ 39.36	\$ 52.38
Natural gas (per Mcf)	\$ 4.04	\$ 3.42	\$ 4.92
Average production costs:			
Production costs (per BOE) (2)	\$ 11.94	\$ 11.92	\$ 11.77

(1)The North Ward Estes and Sanish fields were our only fields that contained 15% or more of our total proved reserve volumes as of December 31, 2013.

(2)Production costs reported above exclude from lease operating expenses ad valorem taxes of \$20.1 million (\$0.59 per BOE), \$16.3 million (\$0.54 per BOE) and \$13.9 million (\$0.56 per BOE) for the years ended December 31, 2013, 2012 and 2011, respectively.

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Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2013. A net well is 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
Rocky Mountains	3,441	1,082	413	221	3,854	1,303
Permian Basin	4,091	1,727	386	122	4,477	1,849
Other (2)	479	217	1,666	553	2,145	770
Total	8,011	3,026	2,465	896	10,476	3,922

(1) 141 wells have multiple completions. These 141 wells contain a total of 349 completions. One or more completions in the same bore hole are counted as one well.

(2) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

We have an interest in or operate 33 EOR projects, which include either secondary (waterflood) or tertiary (CO₂ injection) recovery efforts, and aggregate production from such EOR fields averaged 15.5 MBOE/d during 2013 or 16% of our 2013 daily production. For these areas, we need to use enhanced recovery techniques in order to maintain oil and gas production from these fields.

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 drilling activity for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2013:						
Development	376	1	377	185.5	1	186.5
Exploratory	43	8	51	35.2	7.5	42.7
Total	419	9	428	220.7	8.5	229.2
2012:						
Development	324	-	324	140.4	-	140.4
Exploratory	68	5	73	47.8	4.7	52.5
Total	392	5	397	188.2	4.7	192.9
2011:						
Development	218	3	221	93.9	1.5	95.4
Exploratory	60	3	63	36.6	3.0	39.6
Total	278	6	284	130.5	4.5	135.0

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As of December 31, 2013, 23 operated drilling rigs were active on our properties. The breakdown of our operated rigs by geographic area is as follows:

	Drilling Rigs
Northern Rocky Mountains	18
Central Rocky Mountains	3
North Ward Estes	2
Total	23

Hydraulic Fracturing

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

Whiting’s proved undeveloped reserve quantities that are associated with hydraulic fracture treatments consist of substantially all of our proved undeveloped reserves, or 186.1 MMBOE.

In November 2010, we had a well control incident involving one well in our Sanish field, whereby the North Dakota Industrial Commission (“NDIC”) filed a complaint against Whiting alleging the violation of regulations. This matter resulted in us entering into a consent agreement with the NDIC, pursuant to which we paid \$4,357 in costs, donated \$15,000 to the North Dakota Abandoned Oil and Gas Well Plugging and Site Reclamation Fund, and agreed to implement certain operational procedures. In addition, on February 13, 2014, we had a well control incident during drilling operations involving one well in our Hidden Bench field in North Dakota. The well was quickly brought under control with no liquids leaving the location, and there were no resulting injuries. Appropriate regulatory agencies were notified of the incident. Other than these incidents, we are not aware of any environmental incidents, citations or suits related to hydraulic fracturing operations involving oil and gas properties that we operate or our non-operated interests.

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

- we follow fracturing and flowback procedures that comply with or exceed NDIC or other state requirements;
- we train all company and contract personnel, who are responsible for well preparation, fracture stimulation and flowback, on our procedures;
- we have implemented the incremental procedures of running a well casing caliper; visually inspecting the surface joint of intermediate casing; and if a lighter wall joint of casing or drilling wear is detected, the minimum burst pressure is reduced accordingly;
- for wells that are within one mile of major bodies of water or locations that lead to bodies of water, we construct sufficient berming around the well location prior to initiating fracturing operations;
-

we run fracturing strings in certain situations when extra precaution is warranted, such as where the anticipated maximum treating pressure for the well is greater than the pressure rating of the intermediate casing or in areas located within one mile of major bodies of water; and

- we are constructing a facility in North Dakota to treat and dispose of flow fluids from well stimulations.

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

Delivery Commitments

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

We have also entered into physical delivery contracts which require us to deliver fixed volumes of natural gas and crude oil. As of December 31, 2013, we had delivery commitments of 4.0 Bcf of natural gas (or 15% of total 2013 natural gas production) for the year ended December 31, 2014. These contracts relate to gas production at our Boies Ranch field in Rio Blanco County, Colorado and our Flat Rock field in Uintah County, Utah. We believe that our current production and proved reserves are adequate to meet these delivery commitments. As of December 31, 2013, we also had delivery commitments of 9.1 MMBbl of crude oil (or 34% of total 2013 oil production), 11.0 MMBbl (41%), 12.8 MMBbl (47%), 14.6 MMBbl (54%) and 16.4 MMBbl (61%) for the years ended December 31, 2015, 2016, 2017, 2018 and 2019, respectively. These contracts are tied to oil production at our Redtail field in the DJ Basin in Weld County, Colorado, and we expect to fulfill these delivery commitments from the future production from this field. See “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of this Annual Report on Form 10-K for more information about our delivery commitments under these agreements.

Item 3. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management’s opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 14, 2014, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	67	Chairman and Chief Executive Officer
James T. Brown	61	President and Chief Operating Officer
Mark R. Williams	57	Senior Vice President, Exploration and Development
Bruce R. DeBoer	61	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	43	Vice President, Human Resources
Steven A. Kranker	52	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	55	Vice President, Operations
David M. Seery	59	Vice President, Land
Michael J. Stevens	48	Vice President and Chief Financial Officer
Brent P. Jensen	44	Controller and Treasurer

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

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Effective January 1, 2011, Mr. Volker stepped down as President, but remains Chairman and Chief Executive Officer. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has 42 years of experience in the oil and gas industry. Mr. Volker has a Bachelor's degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager; in January 2000, he became Vice President of Operations; and in May 2007, he became Senior Vice President. Effective January 1, 2011, Mr. Brown was elected President and Chief Operating Officer. Mr. Brown has 39 years of oil and gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming with a Bachelor's degree in civil engineering and the University of Denver with an MBA.

Mark R. Williams joined us in December 1983 as Exploration Geologist and has been Vice President of Exploration and Development since December 1999. Mr. Williams was elected Senior Vice President, Exploration and Development effective January 1, 2011. He has 33 years of domestic and international experience in the oil and gas industry. Mr. Williams holds a Master's degree in geology from the Colorado School of Mines and a Bachelor's degree

in geology from the University of Utah.

Bruce R. DeBoer joined us as Vice President, General Counsel and Corporate Secretary in January 2005. From January 1997 to May 2004, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has 34 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science degree in political science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

Heather M. Duncan joined us in February 2002 as Assistant Director of Human Resources and in January 2003 became Director of Human Resources. In January 2008, she was appointed Vice President of Human Resources. Ms. Duncan has 17 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts degree in anthropology and an MBA from the University of Colorado. She is a certified Senior Professional in Human Resources.

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Steven A. Kranker joined us in March 2013 as First Director – Acquisitions and Reservoir Engineering and became Vice President of Reservoir Engineering and Acquisitions in July 2013. Prior to joining Whiting, Mr. Kranker held positions at several companies engaged in oil and gas exploration and development, including Manager of Reserves at Bill Barrett Corporation from June 2012 to March 2013, President of Earth Energy Reserves, Inc. from July 2010 to June 2012, and various positions at Forest Oil Corporation, including Corporate Engineering Manager, from May 2001 to July 2010. Mr. Kranker has 29 years of acquisition and reservoir engineering experience, including Brunei Shell Petroleum, Arco Alaska Inc., Maxus Exploration, Conoco Inc. and Shell Western E&P Inc. He received his Bachelor of Science degree in petroleum engineering from the Colorado School of Mines. Mr. Kranker is a member of the Society of Petroleum Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations. Mr. Ross has 31 years of oil and gas experience, including 17 years with Amoco Production Company where he served in various technical and managerial positions. Mr. Ross holds a Bachelor of Science degree in mechanical engineering from the South Dakota School of Mines and Technology. He is a registered Professional Engineer, a member of the Society of Petroleum Engineers and was a past Chairman of the North Dakota Petroleum Council.

David M. Seery joined us as our Manager of Land in July 2004 as a result of our acquisition of Equity Oil Company, where he was Manager of Land and Manager of Equity's Exploration Department, positions he had held for more than five years. He became our Vice President of Land in January 2005. Mr. Seery has 33 years of land experience including staff and managerial positions with Marathon Oil Company. Mr. Seery holds a Bachelor of Science degree in business administration from the University of Montana. He is a registered Land Professional and has held various duties with the Denver Association of Petroleum Landmen.

Michael J. Stevens joined us in May 2001 as Controller, became Treasurer in January 2002 and became Vice President and Chief Financial Officer in March 2005. His 27 years of oil and gas experience includes eight years of service in various positions including Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a Certified Public Accountant.

Brent P. Jensen joined us in August 2005 as Controller, and he became Controller and Treasurer in January 2006. He was previously with PricewaterhouseCoopers L.L.P. in Houston, Texas, where he held various positions in their oil and gas audit practice since 1994, which included assignments of four years in Moscow, Russia and three years in Milan, Italy. He has 20 years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree from the University of California, Los Angeles.

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

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PART II

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

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL." The following table shows the high and low sale prices for our common stock for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2013		
Fourth quarter (ended December 31, 2013)	\$ 70.57	\$ 56.40