WHITING PETROLEUM CORP
Form 10-K
February 27, 2015
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, 2014

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 80290 2300
(Address of principal executive offices) (Zip code)

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

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

Title of Class	Name of each exchange on which registered
Common Stock, $0.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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, 2014: $9,569,978,297.

Number of shares of the Registrant's common stock outstanding at February 13, 2015: 167,041,054 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2015 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, used in reference to natural gas or CO2.

"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.

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

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

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

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

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

"EOR" Enhanced oil recovery.

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

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

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

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

“ISDA” International Swaps and Derivatives Association, Inc.

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

“LIBOR” London interbank offered rate.

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

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas or CO2.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet, used in reference to natural gas or CO2.

“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 casing perforations into the formation within that stage.

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

“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

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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.

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

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

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

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

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

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

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

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

"proved undeveloped reserves" Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates 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, CO2 or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for in-situ combustion.

“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 of proved reserves and exploration activities. As of December 31, 2014, our estimated proved reserves totaled 780.3 MMBOE, representing a 78% increase in our proved reserves since December 31, 2013. Our 2014 average daily production was 114.5 MBOE/d and results in an average reserve life of approximately 18.7 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2014, their corresponding pre-tax PV10% values, and our fourth quarter 2014 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2014:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2014 Average Daily Production (MBOE/d)
Rocky Mountains (3)	528.6	35.0	432.9	635.7	83%	$ 12,517.9	116.2
Permian Basin	110.9	19.0	18.7	133.0	83%	1,460.9	11.5
Other (4)	4.1	0.7	40.4	11.6	35%	156.6	3.6
Total	643.6	54.7	492.0	780.3	82%	$ 14,135.4	131.3
Discounted Future Income Taxes						(3,292.0)	
Standardized Measure of Discounted Future Net Cash Flows						$ 10,843.4	

(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, 2014, 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) Includes oil and gas properties located in Colorado, Montana, North Dakota, Utah and Wyoming.

(4) Other primarily includes oil and gas properties located in Arkansas, 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, such as the Kodiak Acquisition discussed below under “Acquisitions and Divestitures”. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities.

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, such as the Kodiak Acquisition discussed below under "Acquisitions and Divestitures".

During 2014, we incurred $3.2 billion in exploration, development and acreage expenditures including $3.0 billion for the drilling of 611 gross (257.1 net) wells. Of these new wells, 253.0 (net) resulted in productive completions and 4.1 (net) were unsuccessful, yielding a 98% success rate.

Our current 2015 E&D budget is $2.0 billion, and included in this amount is approximately $59 million in acreage acquisition costs. The 2015 budget of $2.0 billion represents a substantial decrease from the $3.2 billion in E&D (which amount also includes acreage expenditures) we incurred in 2014. This reduced capital budget is in response to the significantly lower crude oil prices experienced during the fourth quarter of 2014 and continuing into 2015. We expect to fund substantially all of our 2015 E&D budget using net cash provided by operating activities, cash on hand, borrowings under our credit facility, or through the issuance of additional debt or equity securities.

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

Our significant acquisitions and divestitures during the last two years are summarized below. 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 additional information on these acquisitions and divestitures.

2014 Acquisitions. On December 8, 2014, we completed the acquisition of Kodiak Oil & Gas Corp. (now known as Whiting Canadian Holding Company ULC, "Kodiak") whereby we acquired all of the outstanding common stock of Kodiak (the "Kodiak Acquisition"). Pursuant to the terms of the Kodiak Acquisition agreement, Kodiak shareholders received 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they owned. Total consideration for the Kodiak Acquisition was $1.8 billion, consisting of the 47,546,139 Whiting common shares issued at the market price of $37.25 per share on the date of issuance plus the fair value of Kodiak's outstanding equity awards assumed by Whiting. The aggregate purchase price of the transaction was $4.3 billion, which includes the assumption of Kodiak's outstanding debt of $2.5 billion as of December 8, 2014 and the net cash acquired of $19 million.

As a result of the Kodiak Acquisition, Whiting acquired approximately 327,000 gross (178,000 net) acres located primarily in North Dakota, including interests in 778 producing oil and gas wells and undeveloped acreage. Approximately 10,000 of the net acres acquired were located in Wyoming and Colorado. The producing properties had estimated proved reserves of 191.8 MMBOE as of the acquisition date, 86% of which are crude oil and NGLs.

The acquisition significantly expanded our presence in the Williston Basin, adding undeveloped acreage, oil and natural gas reserves and production that were complementary to our existing asset base and operations in this area. As a result of this acquisition, we became the largest Bakken/Three Forks producer in the Williston Basin as of the acquisition date.

2014 Divestitures. On March 27, 2014, we completed the sale of approximately 49,900 gross (41,000 net) acres in our Big Tex prospect, which consisted mainly of undeveloped acreage as well as our interests in certain producing oil and gas wells, located in the Delaware Basin of Texas for a cash purchase price of $76 million resulting in a pre-tax gain on sale of $12 million. With this divestiture, we no longer own any interests in the Big Tex prospect.

2013 Acquisitions. On September 20, 2013, we completed the acquisition of approximately 39,300 gross (17,300 net) acres in the Williston Basin, including interests in 121 producing oil and gas wells and undeveloped acreage, located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an initial purchase price of $261 million.

2013 Divestitures. On October 31, 2013, we completed the sale of approximately 45,000 gross (32,200 net) acres in our Big Tex prospect, which consisted mainly of undeveloped acreage as well as our interests in certain producing oil and gas wells, located in the Delaware Basin of Texas for a cash purchase price of $151 million, resulting in a pre-tax gain on sale of $11 million. Of the total net acres sold, approximately 30,800 net acres were located in Pecos County, Texas, and approximately 1,400 net acres were 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 EOR 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 million after selling costs and post-closing adjustments. This divestiture resulted in a pre-tax gain on sale of $109 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.

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 to 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, 2014, we have assembled approximately 1,311,800 gross (811,700 net) developed and undeveloped acres in the Williston Basin located in Montana and North Dakota. As of December 31, 2014, we had 16 drilling rigs operating in the Williston Basin. During 2014, the focus of our development in the Williston Basin continued in the Sanish and Parshall, 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 130 MMcf/d. Our Belfield plant located near the Pronghorn field currently has inlet compression in place to process 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. We are also currently constructing a 100% owned gas processing plant in our Cassandra field which is expected to come online during the first quarter of 2015 with a processing capacity of 15 MMcf/d.

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 1,400 gross wells targeting several intervals in the Niobrara formation. As of December 31, 2014, we had approximately 185,700 gross (132,200 net) acres, with four drilling rigs operating in this area. In April 2014, we completed the construction of and brought online a gas processing plant for this area. The plant's current inlet capacity is 20 MMcf/d, and we plan to further expand the plant's capacity to 70 MMcf/d in the second quarter of 2015. We expect our Redtail field will be another growth platform for Whiting in 2015 and beyond.

Developing Existing Properties. Our current property base, which includes our acquisitions over the past 11 years, provides us with numerous low-risk opportunities for exploration and development drilling. As of December 31, 2014, we have identified a drilling inventory of over 5,600 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 CO_2 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 290 MMcf/d of recycled CO_2, thereby maximizing our recovery of oil and gas from this reservoir.

Growing Through Accretive Acquisitions. From 2004 to 2014, we completed 21 separate significant acquisitions of producing properties for estimated proved reserves of 445.2 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, closing purchases and then effectively managing properties we acquire. We intend to selectively pursue the acquisition of properties complementary to our core operating areas, as demonstrated by the Kodiak Acquisition, which closed on December 8, 2014 and expanded our presence in the Williston Basin located in Montana and North Dakota.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of our exposure to commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings, internally generated cash flow and certain oil and gas property 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 oil and 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, 2014, we had interests in 11,654 gross (4,471 net) productive wells across approximately 1,610,800 gross (886,700 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 18.7 years based on year-end 2014 proved reserves and 2014 production.

Experienced Management Team. Our management team averages 29 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 30 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

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 9,100 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 26 years of experience managing CO_2 floods, which provides us with the ability to pursue other CO_2 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, and to help us to further understand unconventional oil plays. This knowledge has given us the confidence to assemble over 600,000 gross acres in four oil resource plays, located in three separate basin areas that were new to us.

As a result of our successful testing of cemented liner and plug-and-perf completion designs across all of our prospect areas, in January 2014 we began using this technique for all of our completions in the Williston Basin, resulting in a significant improvement in initial production rates. We have continued to evaluate modifications to our completion techniques, including varying the number of completion stages, utilizing different fracture stimulation fluids including slickwater, and increasing the volume of sand and ceramic proppant used in these fluids. In 2015, we plan to continue use of our state-of-the-art completion design on a majority of the wells we drill in the Williston Basin. We are also utilizing this completion technique in the Niobrara formation in the DJ Basin of Colorado 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, 2014 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.

Rocky Mountains (1):	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (in millions)
PDP	261.4	18.9	247.8	321.6	51%	
PDNP	0.6	0.1	1.1	0.8	-%	
PUD	266.6	16.0	184.0	313.3	49%	
Total proved	528.6	35.0	432.9	635.7	100%	$ 6,418.0
Total probable	308.3	10.0	235.1	357.5		$ 8,062.1
Total possible	107.5	8.8	88.9	131.1		$ 3,113.6
Permian Basin:						
PDP	53.4	5.8	10.4	60.9	46%	
PDNP	14.4	3.6	2.6	18.4	14%	
PUD	43.1	9.6	5.7	53.7	40%	
Total proved	110.9	19.0	18.7	133.0	100%	$ 1,490.2
Total probable	23.9	8.3	29.3	37.1		$ 446.0
Total possible	71.2	16.9	5.8	89.1		$ 692.0
Other (2):						
PDP	3.5	0.5	32.9	9.5	82%	
PDNP	0.3	0.1	3.4	1.0	9%	
PUD	0.3	0.1	4.1	1.1	9%	
Total proved	4.1	0.7	40.4	11.6	100%	$ 16.4
Total probable	2.0	0.4	13.7	4.7		$ 41.8
Total possible	1.4	0.1	22.9	5.3		$ 97.5
Total Company:						
PDP	318.3	25.2	291.1	392.0	50%	
PDNP	15.3	3.8	7.1	20.2	3%	
PUD	310.0	25.7	193.8	368.1	47%	
Total proved	643.6	54.7	492.0	780.3	100%	$ 7,924.6
Total probable	334.2	18.7	278.1	399.3		$ 8,549.9
Total possible	180.1	25.8	117.6	225.5		$ 3,903.1

(1) Includes oil and gas properties located in Colorado, Montana, North Dakota, Utah and Wyoming.
(2) Other primarily includes oil and gas properties located in Arkansas, 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 or transported by rail to terminals, market hubs, refineries or storage facilities. The table below presents percentages by purchaser that accounted for 10% or more of our total oil,

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NGL and natural gas sales for the years ended December 31, 2014, 2013 and 2012. 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.

	2014	2013	2012
Plains Marketing LP	17%	21%	20%
Shell Trading US	10%	14%	14%
Bridger Trading LLC	10%	8%	11%
Eighty Eight Oil Company	6%	11%	11%

Title to Properties

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

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

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. 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.

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.

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

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

On February 25, 2014 the DOT issued an emergency order requiring all persons to ensure crude oil is properly tested and classed prior to offering such product into transportation, and to assure all shipments by rail of crude oil be handled as a Packing Group I or II hazardous material. Also in February 2014, the Association of American Railroads entered into a voluntary agreement with the DOT to implement certain restrictions around the movement of crude oil by rail. In May 2014, the DOT issued an Emergency Restriction/Prohibition Order requiring each railroad carrier operating trains transporting 1,000,000 gallons or more of Bakken crude oil to provide notice to state officials regarding the expected movement of the trains through the counties in each state. The PHMSA and FRA have also issued safety advisories and alerts regarding oil transportation, have issued a report focused on the increased volatility and flammability of Bakken crude oil as compared with other crudes in the U.S. and have various rulemaking proceedings underway.

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

Regulation of 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, none of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was $36 million as of December 31, 2014. 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.

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:

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

· to pay some or all of the costs of any such action.

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

Oil Pollution Act. The Oil Pollution Act of 1990 (“OPA”) and regulations issued under OPA impose strict, joint and several liability on “responsible parties” for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” includes the owner or operator of an onshore facility and the lessee, permittee or holder of a right of use and easement of the area in which an offshore facility is located. OPA establishes a liability limit for onshore facilities of $350 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75 million per spill damages. These limits do not apply if the spill is caused by a responsible party’s gross negligence or willful misconduct; the spill resulted from a responsible party’s violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President may increase the amount of financial responsibility required under OPA by up to $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation 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.

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

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located in the states of Colorado, Michigan, Montana, North Dakota, Texas and Wyoming, 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.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. In addition, the EPA is currently studying wastewater and stormwater discharges from hydraulic fracturing facilities. A proposed rule to amend the Effluent Limitations Guidelines and Standards for the oil and gas extraction category which would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works is expected in early 2015. The EPA announced in 2015 that it would directly regulate methane emissions from oil and natural gas wells for the first time as part of President Obama's Climate Action Plan. As part of this strategy, the EPA will propose in the summer of 2015 a rule to set methane and volatile organic compound emissions standards for new and modified oil and natural gas wells. The final rule is expected in 2016. 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. In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could ban, restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, 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 prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities and the calculation of our reserves.

In addition, on July 3, 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a causal connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. Such studies may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Further, on May 19, 2014, the EPA published an Advance Notice of Proposed Rulemaking ("ANPR") under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties.

Global Warming and Climate Change. 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 (the "PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first becoming subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining “best available control technology” standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis 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.

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

The EPA took additional action under the CAA in June 2014. In accordance with President Obama’s Climate Action Plan, on June 18, 2014, the EPA proposed rules to reduce carbon emissions from electric generating units. The proposal, commonly called the “Clean Power Plan,” requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2020, with the reductions to be fully phased in by 2030. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 30% from 2005 levels. As proposed, states are given substantial flexibility in meeting their emission reduction targets and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units or renewable energy alternatives. It is not possible at this time to predict what requirements might be adopted by the EPA in the final rule expected in 2015, or how any such final rule would impact our business.

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, NGLs and natural gas that we produce. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act (“OCSLA”), the National Environmental Policy Act (“NEPA”) and the Coastal Zone Management Act (“CZMA”) require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and potentially an environmental impact statement. The CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Employees

As of December 31, 2014, we had 1,282 full-time employees, including 43 senior level geoscientists and 84 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

Available Information

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

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Item 1A. Risk Factors

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

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

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. 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 level of global oil and natural gas inventories;
- 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;
- developments of United States energy infrastructure, such as President Obama’s recent veto of legislation that would have allowed the Keystone XL pipeline from Hardesty, Alberta to Cushing, Oklahoma to proceed 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.

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

Oil prices have fallen significantly since reaching highs of over $105.00 per Bbl in June 2014, dropping below $45.00 per Bbl in January 2015. Natural gas prices have also declined from over $4.80 per Mcf in April 2014 to below $2.60 per Mcf in February 2015. In addition, forecasted prices for both oil and gas for 2015 have also declined.

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. At the time of the last redetermination, the applicable oil and gas prices were $92.68 per Bbl and $3.88 per Mcf, whereas the quoted NYMEX prices for oil and gas on February 13, 2015 were $53.67 per Bbl and $2.81 per Mcf.

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

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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 CO_2;
- 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.

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, 2014, we had $1.4 billion in borrowings and $3 million in letters of credit outstanding under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit facility with $3.1 billion of available borrowing capacity, as well as $3.9 billion of senior notes outstanding and $350 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.

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
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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. Because oil and gas prices are principal inputs into the valuation of our reserves, if oil and gas prices remain at their current levels for a prolonged period or go lower, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas' credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, 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.

In conjunction with the Kodiak Acquisition in December 2014, we assumed Kodiak's outstanding principal amount of $800 million of 8.125% Senior Notes due December 2019, $350 million of 5.5% Senior Notes due January 2021 and $400 million of 5.5% Senior Notes due February 2022 (the "Kodiak Notes"). On January 7, 2015, as required under the terms of the indentures governing the Kodiak Notes (the "Kodiak Indentures") upon a change in control of Kodiak, we offered to repurchase at 101% of par all $1,550 million principal amount of Kodiak Notes outstanding. The repurchase offer expires on March 3, 2015. We expect to fund any payments due as a result of such repurchase offer with borrowings under our revolving credit facility, which would reduce availability under such facility.

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, Texas and Wyoming, 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.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. In addition, the EPA is currently studying wastewater and stormwater discharges from hydraulic fracturing facilities. A proposed rule to amend the Effluent Limitations Guidelines and Standards for the oil and gas extraction category which would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works is expected in early 2015. The EPA announced in 2015 that it would directly regulate methane emissions from oil and natural gas wells for the first time as part of President Obama's Climate Action Plan. As part of this strategy, the EPA will propose in the summer of 2015 a rule to set methane and volatile organic compound emissions standards for new and modified oil and natural gas wells. The final rule is expected in 2016. 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. In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could ban, restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, 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 prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities and the calculation of our reserves.

In addition, on July 3, 2014, major university and U.S. Geological Survey researchers published a study purporting to find a causal connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. Such studies may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Further, on May 19, 2014, the EPA published an Advance Notice of Proposed Rulemaking ("ANPR") under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties.

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

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 $587 million impairment write-down during 2014 for the partial impairment of non-core oil and gas producing properties, which are not currently being developed, in Colorado, Louisiana, North Dakota and Utah related to the decrease in oil and gas prices at December 31, 2014. A write-down constitutes a non-cash charge to earnings. Oil and gas prices have continued to decline since December 31, 2014 which may cause us to incur additional impairments that could have a material adverse effect on our results of operations in the period recognized.

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 CO_2 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 CO_2 injection as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Under our CO_2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO_2 to us and other parties with whom it has CO_2 contracts, then the supplier may reduce the amount of CO_2 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 CO_2 available to us, we may not have sufficient CO_2 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 CO_2 as part of our enhanced recovery techniques.

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, 2014, proved undeveloped reserves comprised 40% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $762 million at the North Ward Estes field as of December 31, 2014. This field encompasses 11% 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 commercially viable 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.

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

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

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

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

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

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. The 12-month average prices used for the year ended December 31, 2014 were $94.99 per Bbl and $4.35 per Mcf, whereas the quoted NYMEX prices for oil and gas on February 13, 2015 were $53.67 per Bbl and $2.81 per Mcf. 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, 2014 would have decreased by $21 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, 2014 would have decreased by $179 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. Also, our oil, NGL and natural gas production depends in large part on the proximity and capacity of pipeline systems and transportation facilities which are mostly owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. Similarly, curtailments or damage to pipelines and other transportation facilities used to transport oil, NGLs and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailments or damage to the gathering systems could also require finding alternative means to transport the oil, NGLs and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, 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 and has been followed by additional emergency orders and safety advisories and alerts. An accident involving rail cars could result in significant personal injuries and property and environmental damage. Additionally, added regulations currently being considered 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.

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:

- 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 and making certain restricted payments, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. The Kodiak Indentures restrict us from incurring additional indebtedness and making certain restricted payments, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.25 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 (including the Kodiak Indentures) governing our and Kodiak's 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, agreements with industry partners and oil and gas property divestments. We intend to finance future capital expenditures with cash flow from operations, cash on hand and 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.

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

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

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

Unless production is established on our undeveloped acreage, the underlying leases will expire. As of December 31, 2014, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 26% in 2015, 29% in 2016 and 13% in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

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

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, 2014, we had identified a drilling inventory of over 5,600 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, 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 2014, we recorded a $45 million non-cash charge for the impairment of unproved oil and gas properties in Louisiana, Michigan, Montana, North Dakota and Texas, as well as a $21 million non-cash charge for the impairment of unproved CO_2 properties in New Mexico. 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 2014, we completed 21 separate significant acquisitions of producing properties with a combined purchase price of $6.4 billion for estimated proved reserves as of the effective dates of the acquisitions of 445.2 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including the following:

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

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

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

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

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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 and swap contracts, placed with major financial institutions. As of February 13, 2015, we had contracts covering the sale of between 444,700 and 968,360 barrels of oil per month for all of 2015. All of our oil hedges will expire by December 2017. 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. Our three-way collars only provide partial protection against declines in market prices due to the fact that when the market price falls below the sub-floor, the minimum price we will receive will be NYMEX plus the difference between the floor and the sub-floor. Furthermore, if we do not engage in hedging transactions or unwind hedging transactions we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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

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

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

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

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

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

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

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

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· 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 70% of our net productive oil and natural gas wells, which represents 85% of our proved developed producing reserves as of December 31, 2014. 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.

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.

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 (the "PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

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

The EPA took additional action under the CAA in June 2014. In accordance with President Obama's Climate Action Plan, on June 18, 2014, the EPA proposed rules to reduce carbon emissions from electric generating units. The proposal, commonly called the "Clean Power Plan," requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2020, with the reductions to be fully phased in by 2030. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 30% from 2005 levels. As proposed, states are given substantial flexibility in meeting their emission reduction targets and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units or renewable energy alternatives. It is not possible at this time to predict what requirements might be adopted by the EPA in the final rule expected in 2015, or how any such final rule would impact our business.

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 many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

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

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs 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, President and Chief Executive Officer; Peter W. Hagist, Senior Vice President, Planning; Rick A. Ross, Senior Vice President, Operations; Mark R. Williams, Senior Vice President, Exploration and Development; Steven A. Kranker, Vice President, Reservoir Engineering/Acquisitions; David M. Seery, Vice President, Land; or Michael J. Stevens, Vice President and Chief Financial Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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 February 2015, President Obama's Administration released its proposed federal budget for fiscal year 2016 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.

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

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to our information systems could lead to data corruption, communication interruption or otherwise significantly disrupt our business operations.

We may experience difficulties in integrating Kodiak into our businesses, which could cause the combined company to fail to realize many of the anticipated potential benefits of the Kodiak Acquisition.

We acquired Kodiak with the expectation that the acquisition would result in various benefits, including, among other things, operating efficiencies and cost savings. Achieving the anticipated benefits of the Kodiak Acquisition will depend in part upon whether our two companies integrate our businesses in an efficient and effective manner. We may not be able to accomplish this integration process successfully. The difficulties of combining the two companies' businesses potentially will include, among other things:

- the necessity of addressing possible differences, incorporating cultures and management philosophies and the integration of certain operations following the transaction will require the dedication of significant management resources, which may temporarily distract management's attention from the day-to-day business of the combined company; and
- any inability of our management to cause best practices to be applied to the combined company's business.

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An inability to realize the full extent of the anticipated benefits of the transaction, as well as any delays encountered in the transition process, could have an adverse effect upon the revenues, level of expenses and operating results of the combined company, which may affect the value of our common stock.

The market price of our common stock may decline in the future as a result of the Kodiak Acquisition.

The market price of our common stock may decline in the future as a result of the Kodiak Acquisition for a number of reasons, including the unsuccessful integration of Kodiak (including the reasons set forth in the preceding risk factor) or our failure to achieve the perceived benefits of the Kodiak Acquisition, including financial and operating results, as rapidly as or to the extent anticipated by financial or industry analysts. These factors are, to some extent, beyond our control.

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 Colorado, Montana, North Dakota, Utah and Wyoming. As of December 31, 2014, our estimated proved reserves in the Rocky Mountains region were 635.7 MMBOE (83% oil), which represented 81% of our total estimated proved reserves and contributed 116.2 MBOE/d of average daily production in the fourth quarter of 2014.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations and encompass approximately 169,900 gross (82,600 net) developed and undeveloped acres. Net production in the Sanish and Parshall fields averaged 45.0 MBOE/d for the fourth quarter of 2014, representing a 2% decrease from 46.1 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had three drilling rigs active in the Sanish field. Based on the success of our high density pilot programs in the Sanish field, we commenced a development program drilling nine Bakken wells per spacing unit in the area, an increase over our original plan of three to four wells per spacing unit. Additionally, we have implemented a new slickwater fracture stimulation method using cemented liners at the Sanish field 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 130 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.

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 and 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, 2014, the Lewis & Clark/Pronghorn fields encompassed approximately 339,200 gross (227,400 net) developed and undeveloped acres. Net production in the Lewis & Clark/Pronghorn fields averaged 16.4 MBOE/d in the fourth quarter of 2014, representing a 2% decrease from 16.7 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had one drilling rig operating in the Pronghorn field, which utilizes drilling pads, with two or three wells being drilled from each pad. We have implemented our new completion design in this field utilizing cemented liners and plug-and-perf technology based on our successful testing of this completion technique in 2013. Additionally, we are evaluating our slickwater fracture stimulation method at the Pronghorn field and are encouraged by the results.

At our gas processing plant located south of Belfield, North Dakota, which primarily processes production from the Pronghorn area, there is currently inlet compression in place to process 35 MMcf/d. As of December 31, 2014 the plant was processing over 23 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 121,300 gross (69,000 net) developed and undeveloped acres and 18,800 gross (13,900 net) developed and undeveloped acres, respectively, as of December 31, 2014. Net production at Hidden Bench/Tarpon averaged 22.6 MBOE/d in the fourth quarter of 2014, which represents a 40% increase from 16.2 MBOE/d in the third quarter of 2014. Contributing to this period over period production increase was net production added as a result of the Kodiak Acquisition totaling 10.7 MBOE/d from December 8, 2014, the closing date of the acquisition, through December 31, 2014. As of December 31, 2014, we had four drilling rigs active in the Hidden Bench field. We have also implemented our new completion design at our Hidden Bench/Tarpon fields, utilizing cemented liners and plug-and-perf technology incorporating three to five perforation clusters per fracture stage. This new design has generated positive results, demonstrated by average increases of 20% in initial production rates, as well as 30, 60 and 90-day production rates, from wells recently drilled in these fields. At our Tarpon field we have also implemented a completion technique using cemented liners and coiled tubing, and at our Hidden Bench field, based on the success of our high density drilling pilot in this area, we initiated a development program of drilling eight wells per spacing unit, an increase over our original plan of four wells per spacing unit.

Cassandra Field. Our Cassandra field in Williams County, North Dakota targets the Bakken and Three Forks formations and encompasses approximately 29,800 gross (14,000 net) developed and undeveloped acres as of December 31, 2014. As of December 31, 2014, we had one drilling rig active in the Cassandra field. In 2014, we improved our completion design in this area utilizing cemented liners and plug-and-perf technology with increased proppant volumes resulting in significant improvements in performance.

Missouri Breaks Field. As of December 31, 2014, we had approximately 130,300 gross (82,600 net) developed and undeveloped acres at our Missouri Breaks field located in Richland County, Montana and McKenzie County, North Dakota. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area. In the fourth quarter of 2014, net production from the Missouri Breaks field averaged 6.6 MBOE/d, representing an 8% increase from 6.1 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had three drilling rigs active in the Missouri Breaks field. We have implemented a new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and this new design has significantly improved initial production rates. In addition, we continue to evaluate the slickwater fracture stimulation method used in this area and are encouraged by the initial results.

Other Northern Rocky Mountains. As of December 31, 2014, we had four drilling rigs operating in new areas of the Williston Basin that were acquired in the Kodiak Acquisition. We plan to release two of these rigs during the first quarter of 2015.

Redtail Field. Our Redtail field in the DJ Basin in Weld County, Colorado targets the Niobrara formation and encompasses approximately 185,700 gross (132,200 net) developed and undeveloped acres as of December 31, 2014. In the fourth quarter of 2014, net production from the Redtail field averaged 10.2 MBOE/d, representing an 18% increase from 8.6 MBOE/d in the third quarter of 2014. 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. We are currently completing wells drilled from the Horsetail 30F pad in this area to test a high-density pattern in the Niobrara "A", "B" and "C" zones, with 32 wells per spacing unit. As of December 31, 2014, we had four drilling rigs operating in this area. As a result of the recent decline in crude oil prices, we plan to decrease the number of rigs operating in this area to three for most of 2015. We have implemented our updated completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, which has been yielding improved production results.

In April 2014, we brought online the Redtail gas plant to process the associated gas produced by our wells in this area. The plant's current inlet capacity is 20 MMcf/d, and we plan to further expand the plant's capacity to 70 MMcf/d in the second quarter of 2015.

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2014, the Permian Basin region contributed 133.0 MMBOE (83% oil) of estimated proved reserves to our portfolio of operations, which represented 17% of our total estimated proved reserves and contributed 11.5 MBOE/d of average daily production in the fourth quarter of 2014.

North Ward Estes Field. The North Ward Estes field includes five base leases with 100% working interests in approximately 64,900 gross (62,900 net) developed and undeveloped acres in Ward and Winkler counties, Texas. Current production from our 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 CO_2 floods that we initiated in May 2007. We are currently injecting CO_2 into one of the largest phases of our eight-phase project at North Ward Estes, and all phases of the project subject to CO_2 flood procedures continue to respond positively. In the fourth quarter of 2014, production from the field averaged 9.7 MBOE/d, which represents a 2% increase from 9.5 MBOE/d in the third quarter of 2014. As of December 31, 2014, we were injecting approximately 410 MMcf/d of CO_2 in this field, over half of which is recycled.

North Ward Estes' proved reserves at December 31, 2014 were 40% 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 CO_2. As of December 31, 2014, we currently have under contract the future volumes of CO_2 that we believe are necessary to develop the field's PUDs over at least the next seven years. In addition, we are currently planning for future sources of CO_2 capable of generating sufficient quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, we cannot provide assurance with respect to the timing or actual quantities of CO_2 that will be obtainable for the development of this field's oil and gas reserves.

Other

Our other operations primarily relate to assets in Arkansas, Michigan, Oklahoma and Texas. As of December 31, 2014, these properties contributed 11.6 MMBOE (35% oil) of proved reserves to our portfolio of operations, which represented 2% of our total estimated proved reserves and contributed 3.6 MBOE/d of average daily production in the fourth quarter of 2014.

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Reserves

As of December 31, 2014, 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, 2014 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, 2014) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Developed	333,593	28,935	298,237	412,234
Undeveloped	310,036	25,749	193,783	368,082
Total proved—December 31, 2014	643,629	54,684	492,020	780,316
Probable reserves				
Developed	10,665	3,032	6,463	14,774
Undeveloped	323,579	15,685	271,610	384,532
Total probable—December 31, 2014	334,244	18,717	278,073	399,306
Possible reserves				
Developed	25,363	7,116	2,682	32,926
Undeveloped	154,741	18,728	114,923	192,623
Total possible—December 31, 2014	180,104	25,844	117,605	225,549

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 2014, total extensions and discoveries of 174.8 MMBOE were primarily attributable to successful drilling at our Redtail, Sanish, Hidden Bench, Missouri Breaks, Pronghorn, Tarpon and Cassandra fields. Both the new wells drilled in these areas as well as the PUD locations added as a result of drilling increased our proved reserves.

In 2014, total sales of minerals in place of 2.1 MMBOE were primarily attributable to the disposition of properties in the Big Tex prospect, further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, as well as other property divestitures in the Lucky Ditch, Whiskey Springs and Bridger Lake fields, which decreased our proved reserves.

In 2014, total purchases of minerals in place of 195.6 MMBOE were primarily attributable to the Kodiak Acquisition, whereby we acquired interests in 778 producing oil and gas wells and undeveloped acreage in the Williston Basin, as further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, which increased our proved reserves.

In 2014, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 15.3 MMBOE. Included in these revisions were (i) 15.6 MMBOE of net upward adjustments attributable to reservoir analysis and well performance and (ii) 0.3 MMBOE of downward adjustments caused by lower crude oil prices incorporated into our reserve estimates at December 31, 2014 as compared to December 31, 2013.

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Proved undeveloped reserves. Our PUD reserves increased 98% or 182.0 MMBOE on a net basis from December 31, 2013 to December 31, 2014. The following table provides a reconciliation of our PUDs for the year ended December 31, 2014:

	Total (MBOE)
PUD balance—December 31, 2013	186,096
Converted to proved developed through drilling	(30,064)
Converted to proved developed at EOR projects	(7,940)
Added from extensions and discoveries	135,615
Removed for five-year rule	(2,168)
Removed due to low commodity prices	(218)
Purchased	94,166
Sold	-
Revisions	(7,405)
PUD balance—December 31, 2014	368,082

During 2014, we incurred $767 million in capital expenditures, or $25.51 per BOE, to drill and bring on-line 30.1 MMBOE of PUD reserves. Also during 2014, 7.9 MMBOE of PUD volumes became proved developed reserves at our CO2 EOR project in the North Ward Estes field, at a cost of $39.58 per BOE. Combining the PUD drilling conversions with the PUD EOR conversions, we converted PUDs to proved developed reserves at a cost of $28.45 per BOE during 2014.

In addition, we added 135.6 MMBOE of PUD volumes from extensions and discoveries during the year, 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.

During 2014, we added total PUD volumes of 94.2 MMBOE through acquisitions, of which 90.5 MMBOE were attributable to the Kodiak Acquisition.

Based on our 2014 year end independent engineering reserve report, we will drill all of our individual PUD drilling locations within five years of the date such PUDs were added. 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 EOR PUDs all at once. Due to the large areal extent of the field, this 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 execution of the CO2 project throughout the field all 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.

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 2014 were primarily attributable to 1,916 new probable well locations that were added in 2014 as a result of the Kodiak Acquisition as well as drilling activity across the Rocky Mountains region. Offsetting these increases were 14.0 MMBOE of probable reserves that were converted to proved reserves during 2014, primarily at 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 2014 primarily due to successful drilling at our Redtail, Sanish, Parshall, Lewis & Clark/Pronghorn and Hidden Bench fields. Offsetting these increases were 7.0 MMBOE of possible reserves that were converted to probable during 2014 at our North Ward Estes field and various other fields in the Northern Rocky Mountains, and 11.8 MMBOE of possible reserves were converted to proved during 2014 at the same areas.

At December 31, 2014, our probable reserves were estimated to be 399.3 MMBOE and our possible reserves were estimated to be 225.5 MMBOE, for a total of 624.8 MMBOE. The EOR project at our North Ward Estes field represented 110.3 MMBOE, or 18%, of our total 624.8 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 CO_2. We are currently planning for future sources capable of generating sufficient CO_2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO_2 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 CO_2 that will be obtainable for the development of such reserves.

Preparation of reserves estimates. We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to our internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm Cawley, Gillespie & Associates, Inc. ("CG&A") meets with our technical personnel in our Denver 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 30 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, 2014. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests has been excluded.

	Developed Acreage		Undeveloped Acreage (2)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	71,493	51,181	195,372	119,981	266,865	171,162
Louisiana	23,867	9,191	100,697	91,472	124,564	100,663
Michigan	139,390	61,221	289,465	245,868	428,855	307,089
Montana	97,406	58,886	107,825	68,172	205,231	127,058
New Mexico	17,625	6,387	123,412	114,045	141,037	120,432
North Dakota	813,348	474,804	293,266	209,876	1,106,614	684,680
Oklahoma	56,610	28,391	406	68	57,016	28,459
Texas	252,273	136,831	23,772	18,061	276,045	154,892
Utah	14,301	6,972	431,488	273,295	445,789	280,267
Wyoming	89,162	44,596	44,729	31,548	133,891	76,144
Other (1)	9,810	4,588	912	349	10,722	4,937
Total	1,610,833	886,654	1,611,344	1,172,735	3,222,177	2,059,389

(1) Other includes Alabama, Arkansas, Kansas, Mississippi and Nebraska.
(2) Out of a total of 1,611,344 gross (1,172,735 net) undeveloped acres as of December 31, 2014, 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 26% in 2015, 29% in 2016 and 13% in 2017.

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Production History

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

	Year Ended December 31,		
	2014	2013	2012
Oil production (MMBbl)	33.5	27.0	23.1
NGL production (MMBbl)	3.3	2.8	2.8
Natural gas production (Bcf)	30.2	26.9	25.8
Total production (MMBOE)	41.8	34.3	30.2
Daily production (MBOE/d)	114.5	94.1	82.5
North Ward Estes field production (1)			
Oil production (MMBbl)	3.1	2.9	2.8
NGL production (MMBbl)	0.4	0.4	0.3
Natural gas production (Bcf)	0.3	0.3	0.3
Total production (MMBOE)	3.6	3.4	3.2
Sanish field production (1)			
Oil production (MMBbl)	9.9	9.8	9.0
NGL production (MMBbl)	1.1	1.1	1.2
Natural gas production (Bcf)	5.9	4.8	3.6
Total production (MMBOE)	12.0	11.7	10.8
Average sales prices (before the effects of hedging):			
Oil (per Bbl)	$ 81.50	$ 90.39	$ 83.86
NGLs (per Bbl)	$ 39.17	$ 40.41	$ 39.36
Natural gas (per Mcf)	$ 5.53	$ 4.04	$ 3.42
Average production costs:			
Production costs (per BOE) (2)	$ 11.24	$ 11.94	$ 11.92

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(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, 2014.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $27 million ($0.65 per BOE), $20 million ($0.59 per BOE) and $16 million ($0.54 per BOE) for the years ended December 31, 2014, 2013 and 2012, respectively.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2014. 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	4,670	1,653	413	215	5,083	1,868
Permian Basin	4,098	1,746	374	111	4,472	1,857
Other (2)	467	209	1,632	537	2,099	746
Total	9,235	3,608	2,419	863	11,654	4,471

(1) 137 wells have multiple completions. These 137 wells contain a total of 341 completions. One or more completions in the same bore hole are counted as one well.
(2) Other primarily includes oil and gas properties located in Arkansas, Michigan, Oklahoma and Texas.

We have an interest in or operate 32 EOR projects, which include either secondary (waterflood) or tertiary (CO_2 injection) recovery efforts, and aggregate production from such EOR fields averaged 12.0 MBOE/d during 2014 or 10% of our 2014 daily production. For these areas, we need to use enhanced recovery techniques in order to maintain oil and gas production from these fields.

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Oil and Gas Drilling Activity

We are engaged in numerous drilling activities on properties presently owned, and we intend to drill or develop other properties acquired in the future. The following table sets forth our oil and gas drilling activity for the last three years. Wells drilled to develop our CO2 reserves at our Bravo Dome field in New Mexico have not been included in the drilling activity table below. 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
2014:						
Development	571	1	572	231.5	0.4	231.9
Exploratory	34	5 (1)	39	21.5	3.7	25.2
Total	605	6	611	253.0	4.1	257.1
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

(1) During 2014, we drilled six CO2 wells at our Bravo Dome field that were exploratory dry holes and that have not been included in the drilling results above.

As of December 31, 2014, we had 21 operated drilling rigs active on our properties. The breakdown of our operated rigs by geographic area is as follows:

	Drilling Rigs
Northern Rocky Mountains	16
Central Rocky Mountains	4
North Ward Estes	1
Total	21

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, Texas and Wyoming 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 368.1 MMBOE.

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

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

- we follow fracturing and flowback procedures that comply with or exceed North Dakota Industrial Commission or other state requirements;
- we train all company and contract personnel, who are responsible for well preparation, fracture stimulation and flowback, on our procedures;
- we have implemented the incremental procedures of running a well casing caliper, visually inspecting the surface joint of intermediate casing; and if a lighter wall joint of casing or drilling wear is detected, 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;
- we conduct annual emergency incident response drills in all of our active areas; and
- we are a member of the Sakakawea Area Spill Response LLC ("SASR"), which is composed of 13 oil and gas related companies operating in the Missouri River and Lake Sakakawea region of North Dakota. Members agreed to share spill response resources and maintain SASR-owned water response equipment that can be accessed quickly in the early stages of a spill.

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

Delivery Commitments

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

We have also entered into physical delivery contracts which require us to deliver fixed volumes of crude oil. As of December 31, 2014, we had delivery commitments totaling 12.4 MMBbl of crude oil (or 37% of total 2014 oil production), 17.8 MMBbl (53%), 19.6 MMBbl (59%), 21.5 MMBbl (64%), 23.3 MMBbl (70%) and 6.0 MMBbl (18%) for the years ended December 31, 2015 through 2020, respectively. These contracts are tied to oil production at our Redtail field in the DJ Basin in Weld County, Colorado. As of December 31, 2014, we determined that it is no longer probable that future oil production from our Redtail field will be sufficient to meet the minimum volume requirements specified in these physical delivery contracts, and as a result, we expect to make periodic deficiency payments for any shortfalls in delivering the minimum committed volumes. We currently anticipate that we will under-deliver by a total of approximately 10.4 MMBbl over the duration of the contracts, which would require undiscounted aggregate deficiency payments of approximately $49 million over the next 5 years. We recognize any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred. 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 13, 2015, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	68	Chairman, President and Chief Executive Officer
Peter W. Hagist	54	Senior Vice President, Planning
Rick A. Ross	56	Senior Vice President, Operations
Mark R. Williams	58	Senior Vice President, Exploration and Development
Bruce R. DeBoer	62	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	44	Vice President, Human Resources
Steven A. Kranker	53	Vice President, Reservoir Engineering and Acquisitions
David M. Seery	60	Vice President, Land
Michael J. Stevens	49	Vice President and Chief Financial Officer
Brent P. Jensen	45	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 continued as Chairman and Chief Executive Officer. Effective June 2014, he was again elected President and Chief Executive Officer. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has 43 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.

Peter W. Hagist joined us in October 2005 as Vice President, Operations-Midland. In June 2014, he was elected Senior Vice President of Planning. Mr. Hagist has 33 years of experience in the oil and gas industry and 25 years of experience managing tertiary recovery operations. Prior to joining Whiting, he held management and professional positions with Kinder Morgan CO2 Company and Pennzoil Exploration and Production Company. Mr. Hagist holds a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines. He is a registered Professional Engineer and a member of the Society of Petroleum Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations and in June 2014, he was elected Senior Vice President of Operations. Mr. Ross has 32 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.

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 34 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 35 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 18 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.

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 30 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.

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 34 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 28 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 21 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, 2014		
Fourth quarter (ended December 31, 2014)	$ 78.99	$ 24.13
Third quarter (ended September 30, 2014)	$ 92.92	$ 76.28
Second quarter (ended June 30, 2014)	$ 82.35	$ 68.46
First quarter (ended March 31, 2014)	$ 72.32	$ 54.93
Fiscal Year Ended December 31, 2013		
Fourth quarter (ended December 31, 2013)	$ 70.57	$ 56.40
Third quarter (ended September 30, 2013)	$ 60.65	$ 46.13
Second quarter (ended June 30, 2013)	$ 50.96	$ 42.44
First quarter (ended March 31, 2013)	$ 52.02	$ 43.60

On February 13, 2015, there were 809 holders of record of our common stock.

We have not paid any dividends on our common stock since we were incorporated in July 2003, and we do not anticipate paying any such dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities. Except for limited exceptions, our credit agreement restricts our ability to make any dividends or distributions on our common stock. Additionally, the indentures governing our senior and senior subordinated notes (including Kodiak's senior notes) contain restrictive covenants that may limit our ability to pay cash dividends on our common stock.

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

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

The following graph compares on a cumulative basis changes since December 31, 2009 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Oil Companies, Secondary Index. Such changes have been measured by dividing (a) the sum of (i) the amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2009 in our common stock, the Standard & Poor’s Composite 500 Index and the Dow Jones U.S. Oil Companies, Secondary Index.

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	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
Whiting Petroleum Corporation	$ 100	$ 164	$ 131	$ 121	$ 173	$ 92
Standard & Poor’s Composite 500 Index	100	113	113	128	166	185
Dow Jones U.S. Exploration & Production Index	100	116	110	115	150	132

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Item 6. Selected Financial Data

The consolidated statements of income and statements of cash flows information for the years ended December 31, 2014, 2013 and 2012 and the consolidated balance sheet information at December 31, 2014 and 2013 are derived from our audited financial statements included elsewhere in this report. The consolidated statements of income and statements of cash flows information for the years ended December 31, 2011 and 2010 and the consolidated balance sheet information at December 31, 2012, 2011 and 2010 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent proved property acquisitions beginning on the following closing dates: properties related to the Kodiak Acquisition, December 8, 2014; properties in North Dakota and Montana, September 20, 2013; and properties in Colorado, September 9, 2010. In addition, our historical results also include the effects of our recent proved property divestitures beginning on the following closing dates: properties in the Postle field, July 15, 2013; and properties in Texas, October 31, 2013.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil, NGL and natural gas sales	$ 3,024.6	$ 2,666.5	$ 2,137.7	$ 1,860.1	$ 1,475.3
Gain (loss) on hedging activities	-	(1.9)	2.3	8.8	23.2
Amortization of deferred gain on sale	30.5	31.7	29.5	13.9	15.6
Gain on sale of properties	27.6	128.6	3.4	16.3	1.4
Interest income and other	2.3	3.4	0.5	0.5	0.6
Total revenues and other income	3,085.0	2,828.3	2,173.4	1,899.6	1,516.1
Costs and expenses:					
Lease operating	496.9	430.2	376.4	305.5	268.3
Production taxes	253.0	225.4	171.6	139.2	103.9
Depreciation, depletion and amortization	1,089.5	891.5	684.7	468.2	393.9
Exploration and impairment (1)	854.4	453.2	167.0	84.6	59.4
General and administrative	177.2	138.0	108.6	85.0	64.7
Interest expense	170.6	112.9	75.2	62.5	59.1
Loss on early extinguishment of debt	-	4.4	-	-	6.2
Change in Production Participation Plan liability	-	(7.0)	13.8	(0.9)	12.1
Commodity derivative (gain) loss, net	(100.5)	7.8	(85.9)	(24.8)	7.1
Total costs and expenses	2,941.1	2,256.4	1,511.4	1,119.3	974.7
Income before income taxes	143.9	571.9	662.0	780.3	541.4
Income tax expense	79.2	205.9	247.9	288.7	204.8
Net income	64.7	366.0	414.1	491.6	336.7
Net loss attributable to noncontrolling interest	0.1	0.1	0.1	0.1	-
Net income available to shareholders	64.8	366.1	414.2	491.7	336.7

Preferred stock dividends (2)	-	(0.5)	(1.1)	(1.1)	(64.0)
Net income available to common shareholders	$ 64.8	$ 365.5	$ 413.1	$ 490.6	$ 272.7
Earnings per common share, basic (3)	$ 0.53	$ 3.09	$ 3.51	$ 4.18	$ 2.57
Earnings per common share, diluted (3)	$ 0.53	$ 3.06	$ 3.48	$ 4.14	$ 2.55
Other Financial Information:					
Net cash provided by operating activities	$ 1,815.3	$ 1,744.7	$ 1,401.2	$ 1,192.1	$ 997.3
Net cash used in investing activities	$ (2,860.5)	$ (1,902.5)	$ (1,780.3)	$ (1,760.0)	$ (914.6)
Net cash provided by (used in) financing activities	$ 423.9	$ 812.4	$ 408.1	$ 564.8	$ (75.7)
Capital expenditures	$ 2,888.4	$ 2,772.7	$ 2,171.5	$ 1,804.3	$ 923.8
Consolidated Balance Sheet Information:					
Total assets	$ 14,019.5	$ 8,833.5	$ 7,272.4	$ 6,045.6	$ 4,648.8
Long-term debt	$ 5,628.8	$ 2,653.8	$ 1,800.0	$ 1,380.0	$ 800.0
Total equity (4)	$ 5,703.0	$ 3,836.7	$ 3,453.2	$ 3,029.1	$ 2,531.3

(1) Includes proved oil and gas property impairments of $587 million and CO2 property impairments of $42 million for the year ended December 31, 2014, and proved oil and gas property impairments of $267 million for the year ended December 31, 2013.

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(2) The year ended December 31, 2010 includes a cash premium of $47.5 million for the induced conversion of our 6.25% Perpetual Preferred Stock.
(3) On January 26, 2011, our Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend effective February 22, 2011. Earnings per common share, basic and diluted for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.
(4) No cash dividends were declared or paid on our common stock during the periods presented.

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

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

Overview

We are an independent oil and gas company engaged in exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. Since 2006, we have increased our focus on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth, while continuing to selectively pursue acquisitions that complement our existing core properties, such as the recent acquisition of Kodiak (the "Kodiak Acquisition") discussed below under "Acquisitions and Divestiture Highlights". We believe the combination of acquisitions, subsequent development and organic drilling provides us with a broad set of growth alternatives and allows us to direct our capital resources to what we consider to be the most advantageous investments. We also believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. 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 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, such as the recent Kodiak Acquisition discussed below under "Acquisition and Divestiture Highlights".

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

We continually evaluate our current property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as economic, political and regulatory developments and competition from other sources of energy, as well as the other items discussed in "Risk Factors" in Item IA of this Annual Report on Form 10-K. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2013:

	2013				2014			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude oil	$ 94.34	$ 94.23	$ 105.82	$ 97.50	$ 98.62	$ 102.98	$ 97.21	$ 73.12
Natural gas	$ 3.34	$ 4.10	$ 3.58	$ 3.60	$ 4.93	$ 4.68	$ 4.07	$ 4.04

Oil prices have fallen significantly since reaching highs of over $105.00 per Bbl in June 2014, dropping below $45.00 per Bbl in January 2015. Natural gas prices have also declined from over $4.80 per Mcf in April 2014 to below $2.60 per Mcf in February 2015. In addition, forecasted prices for both oil and gas for 2015 have also declined. Lower oil, NGL and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserves. 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, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. 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 and which is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement. In addition, higher oil and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

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For a discussion of material changes to our proved, probable and possible reserves from December 31, 2013 to December 31, 2014 and our ability to convert PUDs to proved developed reserves, probable reserves to proved reserves, and possible reserves to probable or proved reserves, see "Reserves" in Item 2 of this Annual Report on Form 10-K. Additionally, for a discussion relating to the minimum remaining terms of our leases, see "Acreage" in Item 2 of this Annual Report on Form 10-K, and for a discussion on our need to use enhanced recovery techniques, see "Productive Wells" in Item 2 of this Annual Report on Form 10-K.

2014 Highlights and Future Considerations

Operational Highlights.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish and Parshall fields averaged 45.0 MBOE/d for the fourth quarter of 2014, representing a 2% decrease from 46.1 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had three drilling rigs active in the Sanish field. Based on the success of our high density pilot programs in the Sanish field, we commenced a development program drilling nine Bakken wells per spacing unit in the area, an increase over our original plan of three to four wells per spacing unit. Additionally, we have implemented a new slickwater fracture stimulation method using cemented liners at the Sanish field and are encouraged by the initial results.

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 and 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). Net production in the Lewis & Clark/Pronghorn fields averaged 16.4 MBOE/d in the fourth quarter of 2014, representing a 2% decrease from 16.7 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had one drilling rig operating in the Pronghorn field, which utilizes drilling pads, with two or three wells being drilled from each pad. We have implemented our new completion design in this field utilizing cemented liners and plug-and-perf technology based on our successful testing of this completion technique in 2013. Additionally, we are evaluating our slickwater fracture stimulation method at the Pronghorn field and are encouraged by the results.

At our gas processing plant located south of Belfield, North Dakota, which primarily processes production from the Pronghorn area, there is currently inlet compression in place to process 35 MMcf/d. As of December 31, 2014 the plant was processing over 23 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. Net production at Hidden Bench/Tarpon averaged 22.6 MBOE/d in the fourth quarter of 2014, which represents a 40% increase from 16.2 MBOE/d in the third quarter of 2014. Contributing to this period over period production increase was net production added as a result of the Kodiak Acquisition totaling 10.7 MBOE/d from December 8, 2014, the closing date of the acquisition, through December 31, 2014. As of December 31, 2014, we had four drilling rigs active in the Hidden Bench field. We have also implemented our new completion design at our Hidden Bench/Tarpon fields, utilizing cemented liners and plug-and-perf technology incorporating three to five perforation clusters per fracture stage. This new design has generated positive results, demonstrated by average increases of 20% in initial production rates, as well as 30, 60 and 90-day production rates, from wells recently drilled in these fields. At our Tarpon field we have also implemented a completion technique using cemented liners and coiled tubing, and at our Hidden Bench field, based on the success of our high density drilling pilot in this area, we initiated a development program of drilling eight wells per spacing unit, an increase over our original plan of four wells per spacing unit.

Cassandra Field. Our Cassandra field in Williams County, North Dakota targets the Bakken and Three Forks formations. As of December 31, 2014, we had one drilling rig active in the Cassandra field. In 2014, we improved our completion design in this area utilizing cemented liners and plug-and-perf technology with increased proppant volumes resulting in significant improvements in performance.

Missouri Breaks Field. Our Missouri Breaks field, which is located in Richland County, Montana and McKenzie County, North Dakota, targets the Middle Bakken formation. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area. In the fourth quarter of 2014, net production from the Missouri Breaks field averaged 6.6 MBOE/d, representing an 8% increase from 6.1 MBOE/d in the third quarter of 2014. As of December 31, 2014, we had three drilling rigs active in the Missouri Breaks field. We have implemented a new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and this new design has significantly improved initial production rates. In addition, we continue to evaluate the slickwater fracture stimulation method used in this area and are encouraged by the initial results.

Redtail Field. Our Redtail field in the Denver Julesberg Basin (“DJ Basin”) in Weld County, Colorado targets the Niobrara formation. In the fourth quarter of 2014, net production from the Redtail field averaged 10.2 MBOE/d, representing an 18% increase from 8.6 MBOE/d in the third quarter of 2014. 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. We are currently completing wells drilled from the Horsetail 30F pad in this area to test a high-density pattern in the Niobrara "A", "B" and "C" zones, with 32 wells per spacing unit. As of December 31, 2014, we had four drilling rigs operating in this area. We have implemented our updated completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, which has been yielding improved production results.

In April 2014, we brought online the Redtail gas plant to process the associated gas produced from our wells in this area. The plant's current inlet capacity is 20 MMcf/d, and we plan to further expand the plant's capacity to 70 MMcf/d in the second quarter of 2015.

North Ward Estes Field. The North Ward Estes field is located in the Ward and Winkler counties in Texas, and we continue to have significant development and related infrastructure activity in this field since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in production increases and substantial reserve additions, and our expansion of the CO2 flood in this area continues to generate positive results.

North Ward Estes has been responding positively to the water and CO2 floods that we initiated in May 2007. We are currently injecting CO2 into one of the largest phases of our eight-phase project at North Ward Estes, and all phases of the project subject to CO2 flood procedures continue to respond positively. Net production from North Ward Estes averaged 9.7 MBOE/d for the fourth quarter of 2014, which represents a 2% increase from 9.5 MBOE/d in the third quarter of 2014. As of December 31, 2014, we were injecting approximately 410 MMcf/d of CO2 into the field, over half of which is recycled.

Whiting USA Trust I. On January 28, 2015, the net profits interest that Whiting conveyed to Whiting USA Trust I ("Trust I") terminated as a result of 9.11 MMBOE (which amount is equivalent to 8.20 MMBOE attributable to the net profits interest) having been produced and sold from the underlying properties. Upon termination, the net profits interest in the underlying properties reverted back to Whiting, resulting in an increase in our production volumes of approximately 2.3 MBOE/d as of the termination of the net profits interest.

Financing Highlights. In August 2014, we entered into a Sixth Amended and Restated Credit Agreement with a syndicate of banks which replaced Whiting Oil and Gas' existing credit agreement effective December 8, 2014, the closing date of the Kodiak Acquisition. This amended credit agreement increased the borrowing base under Whiting Oil and Gas' credit facility to $4.5 billion, with aggregate commitments of $3.5 billion. Subsequently in December 2014, the lenders under the credit agreement increased their aggregate commitments under this amended agreement from $3.5 billion to $4.5 billion, of which $3.5 billion relates to commitments to extend revolving credit and $1.0 billion relates to a senior secured delayed draw term loan facility ("Delayed Draw Facility"). The Delayed Draw Facility may be used to provide cash consideration for any repurchase or redemption of Kodiak's outstanding senior notes in connection with the Kodiak Acquisition, to pay transaction costs and for other corporate purposes. A portion of the revolving credit facility, in an aggregate amount not to exceed $100 million, may be used to issue letters of credit for the account of Whiting Oil and Gas and other designated subsidiaries of Whiting Petroleum Corporation. Under the amended credit agreement, the revolving credit facility will mature on December 8, 2019, and the Delayed Draw Facility will mature on December 31, 2015.

In conjunction with the Kodiak Acquisition in December 2014, we assumed Kodiak's outstanding principal amount of $800 million of 8.125% Senior Notes due December 2019, $350 million of 5.5% Senior Notes due January 2021 and $400 million of 5.5% Senior Notes due February 2022 (the "Kodiak Notes"). On January 7, 2015, as required under the terms of the indentures governing the Kodiak Notes (the "Kodiak Indentures") upon a change in control of Kodiak, we offered to repurchase at 101% of par all $1,550 million principal amount of Kodiak Notes outstanding. The repurchase offer expires on March 3, 2015. We expect to fund any payments due as a result of such repurchase offer with borrowings under our revolving credit facility, which would reduce availability under such facility.

2015 Exploration and Development Budget. Our current 2015 exploration and development ("E&D") budget is \$2.0 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand, borrowings under our credit facility, or through the issuance of additional debt or equity securities. This represents a substantial decrease from the \$3.2 billion incurred on E&D (which amount also includes acreage expenditures) during 2014. This reduced capital budget is in response to the significantly lower crude oil prices experienced during the fourth quarter of 2014 and continuing into 2015. We expect to allocate \$1.8 billion of our 2015 budget to exploration and development activity (of which, \$82 million is related to CO_2 development projects), \$59 million for undeveloped acreage and \$123 million for facilities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our E&D budget accordingly or adjust borrowings outstanding under our credit facility as necessary. Our 2015 E&D budget currently is allocated among our major development areas as indicated in the table below. Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital expenditures.

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Development Area	2015 Exploration and Development Budget (in millions)
Northern Rockies	$ 960.5
Central Rockies	386.4
Non-operated	132.9
CO2 EOR project (1)	82.2
Well work and other	194.7
Exploration (2)	61.1
Facilities	123.2
Undeveloped acreage	59.0
Total	$ 2,000.0

(1) 2015 planned capital expenditures at our CO2 EOR project include $80 million for North Ward Estes CO2 purchases.
(2) Comprised primarily of exploration salaries, seismic activities, lease delay rentals and exploratory drilling.

Acquisition and Divestiture Highlights.

Kodiak Acquisition. On December 8, 2014, we completed the Kodiak Acquisition whereby we acquired all of the outstanding common stock of Kodiak. Pursuant to the terms of the Kodiak Acquisition agreement, Kodiak shareholders received 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they owned. Total consideration for the Kodiak Acquisition was $1.8 billion, consisting of the 47,546,139 Whiting common shares issued at the market price of $37.25 per share on the date of issuance plus the fair value of Kodiak's outstanding equity awards assumed by Whiting. The aggregate purchase price of the transaction was $4.3 billion, which includes the assumption of Kodiak's outstanding debt of $2.5 billion as of December 8, 2014 and the net cash acquired of $19 million.

As a result of the Kodiak Acquisition, Whiting acquired approximately 327,000 gross (178,000 net) acres located primarily in North Dakota including interests in 778 producing oil and gas wells and undeveloped acreage. Approximately 10,000 of the net acres acquired were located in Wyoming and Colorado. The producing properties had estimated proved reserves of 191.8 MMBOE as of the acquisition date, 86% of which are crude oil and NGLs.

The acquisition significantly expanded our presence in the Williston Basin, adding undeveloped acreage, oil and natural gas reserves and production that were complementary to our existing asset base and operations in this area. As a result of this acquisition, we became the largest Bakken/Three Forks producer in the Williston Basin as of the acquisition date.

Big Tex Divestiture. In March 2014, we completed the sale of approximately 49,900 gross (41,000 net) acres in our Big Tex prospect, which consisted mainly of undeveloped acreage as well as our interests in certain producing oil and gas wells, located in the Delaware Basin of Texas for a cash purchase price of $76 million resulting in a pre-tax gain on sale of $12 million. With this divestiture, we no longer own any interests in the Big Tex prospect.

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Results of Operations

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

	Year Ended December 31,		
	2014	2013	2012
Net production:			
Oil (MMBbl)	33.5	27.0	23.1
NGLs (MMBbl)	3.3	2.8	2.8
Natural gas (Bcf)	30.2	26.9	25.8
Total production (MMBOE)	41.8	34.3	30.2
Net sales (in millions):			
Oil (1)	$ 2,729.0	$ 2,443.7	$ 1,940.5
NGLs	128.6	114.0	108.9
Natural gas	167.0	108.8	88.3
Total oil, NGL and natural gas sales	$ 3,024.6	$ 2,666.5	$ 2,137.7
Average sales prices:			
Oil (per Bbl) (1)	$ 81.50	$ 90.39	$ 83.86
Effect of oil hedges on average price (per Bbl)	1.29	(1.13)	(1.25)
Oil net of hedging (per Bbl)	$ 82.79	$ 89.26	$ 82.61
Weighted average NYMEX price (per Bbl) (2)	$ 91.55	$ 98.02	$ 94.03
NGLs (per Bbl)	$ 39.17	$ 40.41	$ 39.36
Natural gas (per Mcf) (1)	$ 5.53	$ 4.04	$ 3.42
Effect of natural gas hedges on average price (per Mcf)	-	-	0.06
Natural gas net of hedging (per Mcf)	$ 5.53	$ 4.04	$ 3.48
Weighted average NYMEX price (per Mcf) (2)	$ 4.40	$ 3.66	$ 2.79
Costs and expenses (per BOE):			
Lease operating expenses	$ 11.89	$ 12.53	$ 12.46
Production taxes	$ 6.05	$ 6.56	$ 5.68
Depreciation, depletion and amortization	$ 26.06	$ 25.96	$ 22.67
General and administrative	$ 4.24	$ 4.02	$ 3.59

(1) Before consideration of hedging transactions.

(2) Average NYMEX pricing weighted for monthly production volumes.

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Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $358 million to $3,025 million when comparing 2014 to 2013. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 24%, our NGL sales volumes increased 16% and our natural gas sales volumes increased 12% between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish and Parshall, Redtail, Missouri Breaks and Lewis & Clark/Pronghorn fields. During 2014, oil production from our Hidden Bench/Tarpon fields increased 2,355 MBbl, Sanish and Parshall fields increased 1,830 MBbl, Redtail field increased 1,450 MBbl, Missouri Breaks field increased 795 MBbl, and our Lewis & Clark/Pronghorn fields increased 450 MBbl over the same period in 2013. In addition to the production increases from drilling were 850 MBbl of oil production added across several of our Northern Rockies areas as a result of the Kodiak Acquisition, which closed on December 8, 2014. These production increases were partially offset by the sale of our Postle field, which had oil production of 1,270 MBbl in 2013 but which was fully divested in July 2013, as well as normal field production decline across several of our areas. Our NGLs are generally produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in our oil quantities sold and our NGL quantities sold. As a result, our NGL sales volume increases generally related to the same areas as our oil volume increases, such as our Hidden Bench/Tarpon fields, our Redtail field, our Lewis & Clark/Pronghorn fields and our Sanish and Parshall fields. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 1,750 MMcf at our Sanish and Parshall fields, 1,530 MMcf at our Hidden Bench/Tarpon fields and 1,455 MMcf at our Redtail field. In addition, 615 MMcf of gas production was added as a result of the Kodiak Acquisition. These gas volume increases were partially offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 740 MMcf when comparing 2014 to 2013.

In addition to the above crude oil, NGL and natural gas production-related increases in net revenue was an increase in the average sales price realized for natural gas of 37% in 2014 compared to 2013. These increases were partially offset by decreases in the average sales prices realized for oil and NGLs. Our average price for oil before the effects of hedging decreased 10%, and our average sales price for NGLs decreased 3% between periods.

Gain on Sale of Properties. During 2014, we sold undeveloped acreage as well as our interests in certain producing oil and gas wells in the Big Tex prospect for net proceeds of $76 million in cash, which resulted in a pre-tax gain on sale of $12 million. Also during 2014, we sold certain non-core properties in the Rocky Mountains region for aggregate sales proceeds of $33 million, resulting in a pre-tax gain on sale of $17 million. In July 2013, we sold our interest in the Postle Properties for net proceeds of $810 million, which resulted in a pre-tax gain on sale of $110 million. Additionally during 2013, we sold our interest in certain producing oil and gas wells and undeveloped acreage in the Big Tex prospect for net proceeds of $152 million, which resulted in a pre-tax gain on sale of $13 million for the year ended December 31, 2013. There were no other property divestitures resulting in a significant gain or loss on sale during 2014 or 2013.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2014 were $497 million, a $67 million increase over 2013. Higher LOE in 2014 were primarily related to a $92 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, partially offset by a decrease in well workover activity. Workovers decreased from $82 million in 2013 to $57 million in 2014, primarily due to a lower number of well workovers being conducted at our CO2 project at North Ward Estes.

Our lease operating expenses on a BOE basis, however, decreased when comparing 2014 to 2013. LOE per BOE amounted to $11.89 during 2014, which represents a decrease of $0.64 per BOE from 2013. This decrease was mainly due to higher overall production volumes between periods combined with the decline in well workover costs, as discussed above.

Production Taxes. Our production taxes during 2014 were $253 million, a $28 million increase over the same period in 2013, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.4% and 8.5% for 2014 and 2013, respectively.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $198 million in 2014 as compared to 2013. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2014	2013
Depletion	$ 1,070,503	$ 876,208
Depreciation	5,494	4,700
Accretion of asset retirement obligations	13,548	10,608
Total	$ 1,089,545	$ 891,516

DD&A in 2014 increased over 2013 primarily due to $194 million in higher depletion expense between periods. Of this increase, $191 million related to an increase in our overall production volumes during 2014 and $3 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $26.06 for 2014 represented a slight increase over the 2013 rate of $25.96 due to $2.8 billion in drilling and development expenditures during the past twelve months, which were largely offset by additions to proved and proved developed reserves over this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $401 million in 2014 as compared to 2013. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2014	2013
Exploration	$ 86,803	$ 94,755
Impairment	767,627	358,455
Total	$ 854,430	$ 453,210

Exploration costs decreased $8 million during 2014 as compared to 2013 primarily due to decreases in geological and geophysical ("G&G") activity, lower delay lease rentals paid and lower exploratory dry hole costs, partially offset by rig termination fees of $3 million incurred during 2014. G&G costs, such as seismic studies, amounted to $23 million during 2014 as compared to $30 million during 2013. Delay lease rentals decreased $6 million between periods. Exploratory dry hole costs for 2014 totaled $26 million, primarily related to five exploratory dry holes drilled on our oil and gas properties in 2014, including three in Michigan and two in the Rocky Mountains region, as well as six exploratory dry holes at our CO_2 development project in New Mexico. During 2013, on the other hand, we drilled eight exploratory dry holes in the Rocky Mountains and Permian Basin regions totaling $29 million.

Impairment expense in 2014 primarily related to (i) $587 million in non-cash impairment charges for the partial write-down of non-core proved oil and gas properties, which are not currently being developed, in Colorado, Louisiana, North Dakota and Utah related to the decrease in oil and gas prices at December 31, 2014, (ii) $70 million of amortization of leasehold costs associated with individually insignificant unproved properties, (iii) $66 million in impairment write-downs of undeveloped leases that had reached their expiration dates but that had no wells drilled on them or in areas where we have no further plans to drill or otherwise develop the acreage, (including $21 million in impairment write-downs of undeveloped CO_2 acreage), and (iv) $42 million of impairment write-downs on our CO_2 development properties whose net book values exceeded their undiscounted future net cash flows. Impairment expense in 2013 primarily related to (i) $267 million in non-cash impairment charges for the partial write-down of proved properties, primarily attributable to gas reserves in the Rocky Mountains region and in Michigan, whose net book values exceeded their undiscounted future net cash flows, (ii) $71 million of amortization of leasehold costs associated with individually insignificant unproved properties, and (iii) $19 million of impairment write-downs of undeveloped acreage costs for leases that had reached their expiration dates but where no wells had been drilled on such acreage.

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

	Year Ended December 31,	
	2014	2013
General and administrative expenses	$ 300,814	$ 251,593
Reimbursements and allocations	(123,603)	(113,599)
General and administrative expenses, net	$ 177,211	$ 137,994

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General and administrative expense before reimbursements and allocations increased $49 million during 2014 as compared to 2013 primarily due to transaction-related costs totaling $53 million incurred in 2014 for the Kodiak Acquisition discussed under "Acquisition and Divestiture Highlights" above, as well as higher employee compensation between periods. Employee compensation increased $31 million in 2014 as compared to 2013 due to personnel hired during the past twelve months, as well as general pay increases.

These increases were offset by a decrease in accrued distributions under our Production Participation Plan (the "Plan") between periods. General and administrative expense for 2014 and 2013 includes $24 million and $66 million, respectively, for accrued Plan compensation. On June 11, 2014, the Plan was terminated effective December 31, 2013. Accordingly, there will be no compensation expense incurred under the Plan going forward. Refer to the Deferred Compensation footnote in the notes to consolidated financial statements for more information. Beginning January 1, 2015, we have implemented a new cash bonus structure for our employees to replace the terminated Plan.

The increase in reimbursements and allocations for 2014 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales increased from 5% in 2013 to 6% for 2014, as a result of the increases in general and administrative costs between periods discussed above.

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

	Year Ended December 31,	
	2014	2013
Senior Notes and Senior Subordinated Notes	$ 153,260	$ 73,983
Credit agreement	9,419	27,978
Amortization of debt issue costs and premium	11,984	12,405
Other	63	85
Capitalized interest	(4,084)	(1,515)
Total	$ 170,642	$ 112,936

The increase in interest expense of $58 million between periods was mainly attributable to $79 million in higher interest costs incurred on our notes during 2014. This increase is due to our September 2013 issuance of $1.1 billion of 5% Senior Notes due 2019 and $1.2 billion of 5.75% Senior Notes due 2021, as well as interest costs incurred on the $1.6 billion of senior notes we assumed on December 8, 2014 as part of the Kodiak Acquisition. This increase was partially offset by a $19 million decrease in the amount of interest incurred on our credit agreement during 2014 as compared to 2013 due to lower borrowings outstanding during 2014.

Our weighted average debt outstanding during 2014 was $2.9 billion versus $2.3 billion for 2013. Our weighted average effective cash interest rate was 5.5% during 2014 compared to 4.5% during 2013.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a gain of $101 million for 2014 mainly due to the recognition of a $54 million asset related to two fixed-differential derivative contracts that failed the “normal purchase normal sale” exclusion during the fourth quarter of 2014, as well as the significant downward shift in the futures curve of forecasted commodity prices (“forward price curve”) for crude oil from January 1, 2014 (or the 2014 date on which new contracts were entered into) to December 31, 2014. Commodity derivative (gain) loss, net for 2013, however, resulted in a loss of $8 million due to the less significant upward shift in the same forward price curve from January 1, 2013 (or the 2013 date on which prior year contracts were entered into) to December 31, 2013.

See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of February 13, 2015.

Income Tax Expense. Income tax expense totaled $79 million for 2014 as compared to $206 million of income tax for 2013, a decrease of $127 million that was mainly related to $428 million in lower pre-tax income between periods.

Our effective tax rates for 2014 and 2013 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate increased from 36.0% in 2013 to 55.0% for 2014. This increase is mainly the result of expanded activity in states with higher corporate tax rates, merger costs related to the Kodiak Acquisition that are not deductible and reduced state tax credits.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $529 million to $2,667 million when comparing 2013 to 2012. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 17%, and our natural gas sales volumes increased 4% between periods, while our NGL sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish and Parshall, Missouri Breaks, Lewis & Clark/Pronghorn and Redtail fields. During 2013, oil production from our Hidden Bench/Tarpon fields increased 1,770 MBbl, Sanish and Parshall fields increased 1,100 MBbl, Missouri Breaks field increased 765 MBbl, Lewis & Clark/Pronghorn fields increased 765 MBbl, and our Redtail field increased 610 MBbl over the same period in 2012. These production increases were partially offset by the sale of the Postle Properties in July 2013 and the Whiting USA Trust II (“Trust II”) divestiture in March 2012, which divestitures negatively impacted oil production in 2013 by 1,250 MBbl and 295 MBbl, respectively. The gas volume increase between periods was primarily the result of new wells drilled and completed during 2013, which caused increases in associated gas production of 1,380 MMcf at our Hidden Bench/Tarpon fields, 1,330 MMcf at our Sanish and Parshall fields and 870 MMcf at our Lewis & Clark/Pronghorn fields. These gas volume increases were largely offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 1,080 MMcf when comparing 2013 to 2012. In addition, the Trust II divestiture in March 2012 negatively impacted gas production in 2013 by 545 MMcf.

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in 2013 compared to 2012. Our average price for oil before the effects of hedging increased 8%, our average price for NGLs increased 3% between periods, and our average price for natural gas before the effects of hedging increased 18% between periods.

Gain on Sale of Properties. During 2013, we sold our interest in the Postle Properties for net proceeds of $810 million, which resulted in a pre-tax gain on sale of $110 million. Additionally during 2013, we sold our interest in certain producing oil and gas wells and undeveloped acreage in the Big Tex prospect for net proceeds of $152 million, which resulted in a pre-tax gain on sale of $13 million for the year ended December 31, 2013. There were no other property divestitures resulting in a significant gain or loss on sale during 2013 or 2012.

Lease Operating Expenses. Our LOE during 2013 were $430 million, a $54 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $45 million increase in the cost of oil field goods and services associated with net wells we added during the twelve months ended December 31, 2013, and a $9 million increase in costs at the North Ward Estes CO2 processing facility due to increased production from that field and higher volumes therefore processed through the plant.

Our lease operating expenses on a BOE basis only increased slightly during 2013. LOE per BOE amounted to $12.53 during 2013, which was up from $12.46 per BOE during 2012. This increase was mainly due to the higher costs of oil field goods and services and CO2 processing facility costs in 2013, as discussed above, partially offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during 2013 were $225 million, a $54 million increase over the same period in 2012, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.5% and 8.0% for 2013 and 2012, respectively.

Depreciation, Depletion and Amortization. Our DD&A expense increased $207 million in 2013 as compared to 2012. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2013	2012
Depletion	$ 876,208	$ 673,789
Depreciation	4,700	3,672
Accretion of asset retirement obligations	10,608	7,263
Total	$ 891,516	$ 684,724

DD&A in 2013 increased over 2012 primarily due to $202 million in higher depletion expense between periods. Of this increase, $105 million related to an increase in our overall production volumes during 2013 and $97 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $25.96 for 2013 was 15% higher than the rate of $22.67 for 2012 due to $2.3 billion in drilling and development expenditures during the twelve months ended December 31, 2013, which were partially offset by additions to proved and proved developed reserves over this same time period.

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Exploration and Impairment Costs. Our exploration and impairment costs increased $286 million in 2013 as compared to 2012. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2013	2012
Exploration	$ 94,755	$ 59,117
Impairment	358,455	107,855
Total	$ 453,210	$ 166,972

Exploration costs increased $36 million during 2013 as compared to 2012 primarily due to an increase in G&G activity, higher exploratory dry hole costs, higher delay lease rentals paid and an increase in geology-related general and administrative expenses. G&G costs, such as seismic studies, amounted to $30 million during 2013 as compared to $17 million during 2012. Exploratory dry hole costs for 2013 totaled $29 million, primarily related to eight exploratory dry holes drilled in the Rocky Mountains and Permian Basin regions during 2013. During 2012, on the other hand, we drilled five exploratory dry holes in the Rocky Mountains and Permian Basin regions and in Michigan totaling $18 million. Delay lease rentals increased $7 million between periods, while geology-related general and administrative expenses increased $6 million.

Impairment expense in 2013 primarily related to (i) $267 million in non-cash impairment charges for the partial write-down of proved properties, primarily attributable to gas reserves in the Rocky Mountains region and in Michigan, whose net book values exceeded their undiscounted future cash flows, (ii) $71 million of amortization of leasehold costs associated with individually insignificant unproved properties and (iii) $19 million of impairment write-downs of undeveloped acreage costs for leases that had reached their expiration dates but where no wells had been drilled on such acreage. Impairment expense in 2012 primarily related to (i) the amortization of leasehold costs associated with individually insignificant unproved properties of $54 million, (ii) $47 million of non-cash proved property impairment write-downs, mainly in the Rocky Mountains region and (iii) $6 million of impairment write-downs of undeveloped acreage costs.

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

	Year Ended December 31,	
	2013	2012
General and administrative expenses	$ 251,593	$ 199,943
Reimbursements and allocations	(113,599)	(91,370)

General and administrative expenses, net	$ 137,994	$ 108,573

General and administrative expense before reimbursements and allocations increased $52 million during 2013 as compared to 2012 primarily due to higher employee compensation and an increase in accrued Plan distributions. However, our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained consistent for 2013 and 2012 at about 5%. Employee compensation increased $29 million in 2013 as compared to 2012 due to personnel hired during 2013, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $22 million between periods. This increase was primarily due to a one-time charge under the Plan of $22 million for the sale of the Postle Properties in the third quarter of 2013 and $9 million related to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula), which increases were partially offset by higher accrued Plan distributions of $9 million during 2012 due to the Trust II net profits interest divestiture in 2012.

The increase in reimbursements and allocations for 2013 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties.

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

	Year Ended December 31,	
	2013	2012
Senior Notes and Senior Subordinated Notes	$ 73,983	$ 40,250
Credit agreement	27,978	28,043
Amortization of debt issue costs and premium	12,405	9,518
Other	85	148
Capitalized interest	(1,515)	(2,749)
Total	$ 112,936	$ 75,210

The increase in interest expense of $38 million between periods was mainly attributable to a $34 million increase in the amount of interest incurred on our notes during 2013 as compared to 2012 due to our September 2013 issuance of $1.1 billion of 5% Senior Notes due 2019 and $1.2 billion of 5.75% Senior Notes due 2021. Our weighted average debt outstanding during 2013 was $2.3 billion versus $1.6 billion for 2012. Our weighted average effective cash interest rate was 4.5% during 2013 compared to 4.3% during 2012.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $8 million for 2013 mainly due to the upward shift in the forward price curve for crude oil from January 1, 2013 (or the 2013 date on which new contracts were entered into) to December 31, 2013. Commodity derivative (gain) loss, net for 2012, however, resulted in a gain of $86 million due to a significant downward shift in the same forward price curve from January 1, 2012 (or the 2012 date on which prior year contracts were entered into) to December 31, 2012.

Income Tax Expense. Income tax expense totaled $206 million for 2013 as compared to $248 million of income tax for 2012, a decrease of $42 million that was mainly related to $90 million in lower pre-tax income between periods, as well as $11 million in state tax credits realized during 2013.

Our effective tax rates for 2013 and 2012 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 37.4% in 2012 to 36.0% for 2013. This decrease in rate is mainly attributable to state tax credits and a reduction to the North Dakota corporate tax rate, which created a one-time benefit during 2013.

Liquidity and Capital Resources

Overview. At December 31, 2014, we had $78 million of cash on hand and $5.7 billion of equity, while at December 31, 2013, we had $699 million of cash on hand and $3.8 billion of equity.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 80% and 79% of our total production in 2014 and 2013, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of February 13, 2015, we had derivative contracts covering the sale of approximately 18% of our forecasted 2015 oil production volumes. For a list of all of our outstanding derivatives as of February 13, 2015, see Item 7A, “Quantitative and Qualitative Disclosures about Market Risk.”

Cash Flows from 2014 Compared to 2013. During 2014, we generated $1.8 billion of cash provided by operating activities, an increase of $71 million from 2013. Cash provided by operating activities increased primarily due to higher crude oil, NGL and natural gas production volumes and higher realized sales prices for natural gas, as well as lower exploration costs during 2014. These positive factors were partially offset by lower realized sales prices for oil and NGLs, as well as increased lease operating expenses, production taxes, general and administrative expenses and cash interest expense in 2014 as compared to 2013. Refer to “Results of Operations” for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses during 2014.

During 2014, cash flows from operating activities and cash on hand plus $475 million in net borrowings under our credit agreement and $108 million of proceeds from the sale of properties were used to finance $2.8 billion of drilling and development expenditures, $80 million for purchases of other property and equipment, $46 million of oil and gas property acquisitions (net of cash acquired), $26

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million for the final payment under our Tax Sharing and Indemnification Agreement with Alliant Energy Corporation and $15 million of debt issuance costs.

Cash Flows from 2013 Compared to 2012. During 2013, we generated $1.7 billion of cash provided by operating activities, an increase of $344 million from 2012. Cash provided by operating activities increased primarily due to higher realized sales prices for oil, NGLs and natural gas and higher crude oil and natural gas production volumes during 2013. These positive factors were partially offset by increased lease operating expenses, production taxes, exploration costs, general and administrative expenses and cash interest expense in 2013 as compared to 2012. See "Results of Operations" for more information on the impact of prices and volumes on revenues and for more information on increases in certain expenses during 2013. Cash flows from operating activities plus $2.3 billion of proceeds from the issuance of our Senior Notes and $969 million of proceeds from the sale of properties were used to finance $2.3 billion of drilling and development expenditures, $1.2 billion of net repayments under our credit agreement, $423 million of oil and gas property acquisitions, $254 million for the redemption of our 7% Senior Subordinated Notes due 2014, $43 million in investing derivative purchases (net of cash receipts for settlements), $45 million for purchases of other property and equipment and $30 million of debt issuance costs.

Exploration, Development and Undeveloped Acreage Expenditures. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Rocky Mountains (1)	$ 2,756,647	$ 2,172,462	$ 1,581,934
Permian Basin (2)	379,702	346,812	410,154
Other (3)	45,589	155,918	119,431
Total incurred	$ 3,181,938	$ 2,675,192	$ 2,111,519

(1) For the year ended December 31, 2012, proceeds from the sale of the Belfield gas plant of $66 million have been included as a reduction to expenditures in the Rocky Mountains region.
(2) For the year ended December 31, 2014, amount includes $76 million related to the acquisition of undeveloped acreage and the development of CO_2 reserves and facilities at our Bravo Dome field in New Mexico. For the year ended December 31, 2013 amount includes $21 million related to the acquisition of undeveloped acreage and related facilities at our Bravo Dome field in New Mexico. For the year ended December 31, 2012, amount includes $11 million related to the acquisition of undeveloped acreage at our Bravo Dome field in New Mexico.
(3) Other primarily includes oil and gas properties located in Louisiana, Michigan, Oklahoma and Texas.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2015 E&D budget is $2.0 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand, borrowings under our credit facility, or through the issuance of additional debt or equity securities. This represents a substantial decrease from the $3.2 billion incurred on exploration, development and acreage expenditures during 2014. This reduced capital budget is in response to the significantly lower crude oil prices experienced during the fourth quarter of 2014 and continuing into 2015. We expect to allocate $1.8 billion of our 2015 budget to exploration and development activity, $59 million for undeveloped acreage and $123 million for facilities. Although we have only budgeted $59 million for undeveloped leasehold purchases in 2015, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $2.0 billion, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, agreements with industry partners or divestitures of certain oil and gas property interests. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future, including obligations arising as a result of the recent Kodiak Acquisition. On December 8, 2014, under the terms of the Kodiak Acquisition agreement, we acquired all of the outstanding common stock of Kodiak, whereby Kodiak shareholders received 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they owned, and we assumed or repaid all of Kodiak's outstanding debt as of that date. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

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Credit Agreement. Whiting Oil and Gas, our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2014 had a borrowing base of $4.5 billion, with aggregate commitments of $4.5 billion, of which $3.5 billion relates to commitments to extend revolving credit and $1.0 billion relates to a Delayed Draw Facility. The Delayed Draw Facility may be used to provide cash consideration for any repurchase or redemption of Kodiak's outstanding senior notes in connection with the Kodiak Acquisition, to pay transaction costs and for other corporate purposes. As of December 31, 2014, we had $3.1 billion of available borrowing capacity, which was net of $1.4 billion in borrowings (which includes $925 million we borrowed to repay the debt outstanding under Kodiak's credit facility after the completion of the Kodiak Acquisition) and $3 million in letters of credit outstanding. The revolving credit facility will mature on December 8, 2019, and the Delayed Draw Facility will mature on December 31, 2015.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. At the time of the last redetermination, the applicable oil and gas prices were $92.68 per Bbl and $3.88 per Mcf, whereas the quoted NYMEX prices for oil and gas on February 13, 2015 were $53.67 per Bbl and $2.81 per Mcf. Because oil and gas prices are principal inputs into the valuation of our reserves, if oil and gas prices remain at their current levels for a prolonged period or go lower, our borrowing base could be reduced at the next redetermination date or during future redeterminations. However, we anticipate an increase in our proved reserves since the time of the last redetermination resulting from the Kodiak Acquisition as well as drilling results, which factors are expected to have a positive impact on our borrowing base and may offset any borrowing base reductions driven by a low price environment. Upon a redetermination of our borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

A portion of the revolving credit facility in an aggregate amount not to exceed $100 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of December 31, 2014, $97 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until the expiration date of the agreement, when all outstanding borrowings are due. Interest under the revolving credit facility accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the revolving credit facility.

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

Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

Interest under the Delayed Draw Facility accrues at our option at either (i) a base rate for a base rate loan plus (A) 1.00% per annum through March 8, 2015 and (B) 1.50% per annum from March 9, 2015 through the December 31, 2015 maturity date, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus (A) 2.00% per annum through March 8, 2015 and (B) 2.50% per annum from March 9, 2015 through the December 31, 2015 maturity date. We also incur commitment fees of 0.25% on the unused portion of the aggregate commitments of the lenders under the Delayed Draw Facility.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. The 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. We were in compliance with our covenants under the credit agreement as of December 31, 2014. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

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Under the terms of the credit agreement, at any time during which we have an investment-grade debt rating from Moody's Investors Service, Inc. or Standard & Poor's Ratings Group and we have elected, at our discretion, to effect an investment-grade rating period, (i) certain security requirements, including the borrowing base requirement, and restrictive covenants will cease to apply, (ii) certain other restrictive covenants will become less restrictive, (iii) an asset coverage covenant will be imposed, and (iv) the interest rate margin applicable to all revolving borrowings as well as the commitment fee with respect to the revolving facility will be based upon our debt rating rather than the ratio of outstanding borrowings to the borrowing base.

For further information on the loan security related to our credit agreement, refer to the Long-Term Debt footnote in the notes to consolidated financial statements.

Senior Notes and Senior Subordinated Notes. In September 2013, we issued at par $1.1 billion of 5% Senior Notes due March 2019 (the "2019 Senior Notes") and $800 million of 5.75% Senior Notes due March 2021, and also in September 2013, we issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively, the "2021 Senior Notes"). In September 2010, we issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Senior Subordinated Notes").

Kodiak Senior Notes. In conjunction with the Kodiak Acquisition, Whiting US Holding Company, our wholly-owned subsidiary, became a co-issuer of the Kodiak Notes. Upon closing of the Kodiak Acquisition, the Kodiak Indentures were amended to (i) modify certain covenants and restrictions, (ii) to provide for unconditional and irrevocable guarantees by Whiting Petroleum Corporation and Whiting Oil and Gas Corporation of the prompt payment, when due, of any amounts owed under the Kodiak Notes and the Kodiak Indentures, and (iii) to allow Whiting US Holding Company to become a co-issuer of the Kodiak Notes. Also in conjunction with the Kodiak Acquisition, in December 2014, each of the indentures governing our 2019 Senior Notes, 2021 Senior Notes and 2018 Senior Subordinated Notes (collectively, the "Whiting Notes") were amended to include Whiting US Holding Company, Kodiak and Whiting Resources Corporation (formerly Kodiak Oil & Gas (USA) Inc.) as guarantors.

The indentures governing the Whiting 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. The indentures governing the Kodiak 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 2.25 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. Additionally, the indentures governing the Whiting Notes and the Kodiak Notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, make certain other restricted payments, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of December 31, 2014. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

On January 7, 2015, as required under the Kodiak Indentures upon a change in control of Kodiak, Whiting offered to repurchase at 101% of par all $1,550 million principal amount of Kodiak Notes outstanding. The repurchase offer expires on March 3, 2015. We expect to fund any payments due as a result of such repurchase offer with borrowings under our revolving credit facility.

Shelf Registration Statement. We have on file with the SEC a universal shelf registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

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Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include any penalties that may be incurred under our physical delivery contracts, since we cannot predict with accuracy the amount and timing of any such penalties if incurred. The following table summarizes our obligations and commitments as of December 31, 2014 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below (in thousands):

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 5,600,000	$ -	$ -	$ 3,650,000	$ 1,950,000
Cash interest expense on debt (2)	1,468,613	279,701	559,402	480,250	149,260
Asset retirement obligations (3)	179,931	12,190	24,326	24,615	118,800
Purchase obligations (4)	148,969	68,775	80,194	-	-
Pipeline transportation agreements (5)	113,784	18,794	25,781	19,118	50,091
Drilling rig contracts (6)	278,784	146,141	132,643	-	-
Operating leases (7)	34,602	7,692	14,157	12,537	216
Production Participation Plan liability (8)	113,391	113,391	-	-	-
Total	$ 7,938,074	$ 646,684	$ 836,503	$ 4,186,520	$ 2,268,367

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(1) Long-term debt consists of the principal amounts of the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019, the 8.125% Senior Notes due 2019, the 5.5% Senior Notes due 2021, the 5.75% Senior Notes due 2021, the 5.5% Senior Notes due 2022 and the outstanding borrowings under our credit agreement due in 2019. The $800 million of 8.125% Senior Notes due 2019, $350 million of 5.5% Senior Notes due 2021 and $400 million of 5.5% Senior Notes due 2022 are subject to our repurchase offer in connection with the Kodiak Acquisition that expires on March 3, 2015. See "—2014 Highlights and Future Considerations – Financing Highlights" above for more information.

(2) Cash interest expense on our Senior Subordinated Notes and our Senior Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the December 2019 instrument due date and is estimated at a fixed interest rate of 1.9%.

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

(4) We have three take-or-pay purchase agreements, of which one agreement expires in 2015 and two agreements expire in 2017. One of these agreements contains commitments to buy certain volumes of CO_2 for use in our North Ward Estes EOR project in Texas. Under the remaining two take-or-pay agreements, we have committed to buy certain volumes of water for use in the fracture stimulation process of wells in our Redtail field. Under the terms of these agreements, we are obligated to purchase a minimum volume of CO_2 or water, as the case may be, or else pay for any deficiencies at the price stipulated in the contract. The CO_2 volumes planned for use in the

EOR project in our North Ward Estes field and the water volumes planned for use at our Redtail field currently exceed the minimum volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies under these contracts. The purchasing obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

(5) We have two ship-or-pay agreements with different suppliers, one expiring in 2015 and one expiring in 2017, whereby we have committed to transport a minimum daily volume of CO2 or water, as the case may be, via certain pipelines or else pay for any deficiencies at a price stipulated in the contracts. In addition, we have three pipeline transportation agreements with one supplier, one expiring in 2024 and two expiring in 2025, whereby we have committed to pay fixed monthly reservation fees on dedicated pipelines for natural gas and NGL transportation capacity from our Redtail field, plus a variable charge based on actual transportation volumes.

(6) As of December 31, 2014, we had 18 drilling rigs under long-term contract, all of which were operating in the Rocky Mountains region. Subsequent to December 31, 2014, we early terminated five of these long-term contracts incurring early termination penalties of approximately $27 million. These penalties have been included as contractual commitment amounts in the table above. Of the remaining 13 long-term contracts, seven expire in 2016 and six in 2017. Early termination of the remaining contracts would require termination penalties of $212 million, which would be in lieu of paying the remaining drilling commitments under these contracts. No other drilling rigs working for us are currently under long-term contracts or contracts that

cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(7) We lease 197,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2019, 47,900 square feet of office space in Midland, Texas expiring in 2020, an additional 36,300 square feet of administrative office space in Denver, Colorado assumed in the Kodiak Acquisition expiring in 2016, and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, we entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease agreement expiring in 2015.

(8) In June 2014, we terminated our Production Participation Plan effective December 31, 2013. Pursuant to the terms of the Plan, upon termination we are required to distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination. As of December 31, 2014, a portion of this liability representing a regular distribution under the Plan totaling $41 million had been paid to our third-party payroll administrator. However, these funds were not distributed by the payroll administrator to Plan participants until January 2015. The final Plan distribution payment will be made in June 2015.

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

New Accounting Pronouncements

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

Critical Accounting Policies and Estimates

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

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

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

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

External petroleum engineers independently estimated all of the proved, probable and possible reserve quantities included in this annual report. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2014. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates and impairment calculations (when impairment indicators arise) in the same period that changes to reserve estimates are made.

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

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

Goodwill Impairment. We test our goodwill for impairment annually in the second quarter or when events or changes in circumstances indicate that the fair value of a reporting unit has been reduced below its carrying value. When testing goodwill for impairment, if our qualitative analysis indicates that it is more likely than not that the fair value of the reporting unit is less than its carrying value, we then perform a quantitative impairment test. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings.

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

Production Participation Plan. On June 11, 2014, the Board of Directors terminated our Production Participation Plan (the "Plan"), in which all employees participated, effective December 31, 2013. Prior to Plan termination, interests in oil and gas properties acquired, developed or sold during the year were allocated to the Plan on an annual basis as determined by the Compensation Committee of the Board of Directors. Once allocated, the interests (not legally conveyed) were fixed. The short-term obligation related to the Plan is reflected in the "Current portion of Production Participation Plan liability" line item in our consolidated balance sheets. This obligation at December 31, 2013 was based on cash flows during 2013 and was paid in cash in January 2014. The calculation of this liability depended in part on our estimates of accrued revenues and costs as of December 31, 2013 as discussed below under "Revenue Recognition." The vested long-term obligation related to the Plan at December 31, 2013 is reflected in the "Production Participation Plan liability" line item in the consolidated balance sheets. This liability was derived primarily from reserve report estimates as of that date. Pursuant to the terms of the Plan, upon Plan termination all employees became fully vested, and the fully vested amount due to Plan participants has been reflected as a current payable as of December 31, 2014, as it will be distributed to Plan participants during the first half of 2015. This liability includes the value of proved undeveloped oil and gas properties awarded upon Plan termination, and is based on reserve report estimates and forecasted commodity prices for crude oil, NGLs and natural gas as of the December 31, 2013 termination effective date.

Derivative Instruments and Hedging Activity. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flow to fund our capital programs and manage returns on our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. We primarily

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utilize costless collars and swaps contracts, which are generally placed with major financial institutions, as well as fixed-differential crude oil sales contracts.

All derivative instruments are recorded on the consolidated balance sheet at fair value, other than the derivative instruments that meet the “normal purchase normal sale” exclusion. Changes in the derivatives’ fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the fair value gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to the gain (loss) on hedging activities line item in our consolidated statements of income in the period that the hedged production is delivered.

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

We utilize the counterparties’ valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as these estimates are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

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

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

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

Revenue Recognition. We predominantly derive our revenue from the sale of produced oil, NGLs and natural gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. However, differences have been and are insignificant.

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

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

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

The business combinations completed during the prior three years consisted of oil and gas properties. In general, the consideration we have paid to acquire these properties or companies was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition and consequently, there was no goodwill nor any bargain purchase gains recognized on our business combinations. However, the purchase price allocation associated with the Kodiak Acquisition resulted in the recognition of goodwill. For further information on the Kodiak Acquisition, refer to the Acquisitions and Divestitures footnote in the notes to consolidated financial statements.

Effects of Inflation and Pricing

We experienced increased costs during 2013 and 2014 due to increased demand for oil field products and services. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

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

These risks and uncertainties include, but are not limited to: declines in oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; impacts to financial statements as a result of impairment write-downs; our ability to successfully complete asset dispositions and the risks related thereto; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; our ability to obtain sufficient quantities of CO_2 necessary to carry out our EOR projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; risks relating to any unforeseen liabilities of ours; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal Government that could have a negative effect on the oil and gas industry; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; availability of, and risks associated with, transport of oil and gas; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry; cyber security attacks or failures of our telecommunication systems; our ability to successfully integrate Kodiak after the Kodiak Acquisition and achieve anticipated benefits from the transaction; and other risks described under the caption “Risk Factors” in this Annual Report on Form 10 K. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Annual Report on Form 10-K.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on 2014 production, our income before income taxes for 2014 would have moved up or down $273 million for each 10% change in oil prices per Bbl, $13 million for each 10% change in NGL prices per Bbl and $17 million for each 10% change in natural gas prices per Mcf.

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

Commodity Derivative Contracts

Crude Oil Costless Collars and Swaps. The collared hedges shown in the table below have the effect of providing a protective floor while allowing us to share in upward pricing movements. The three-way collars, however, do not provide complete protection against declines in crude oil prices due to the fact that when the market price falls below the sub-floor, the minimum price we would receive would be NYMEX plus the difference between the floor and the sub-floor. While these hedges are designed to reduce our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil collars outstanding as of December 31, 2014, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2014 would cause a decrease or increase, respectively, of $2 million in our commodity derivative (gain) loss.

The swap contracts shown in the tables below entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. While the fixed-price swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of upward price movements. For the swaps outstanding as of December 31, 2014, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2014 would cause a decrease or increase, respectively, of $17 million in our commodity derivative (gain) loss.

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Our outstanding hedges as of February 13, 2015 are summarized below:

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	01/2015 to 03/2015	100,000	$70.00/$85.00/$107.90
	Crude oil	04/2015 to 06/2015	100,000	$70.00/$85.00/$107.90
	Crude oil	07/2015 to 09/2015	500,000	$47.00/$58.00/$78.99
	Crude oil	10/2015 to 12/2015	500,000	$47.00/$58.00/$78.99
	Crude oil	01/2016 to 03/2016	550,000	$43.18/$53.18/$76.26
	Crude oil	04/2016 to 06/2016	550,000	$43.18/$53.18/$76.26
	Crude oil	07/2016 to 09/2016	550,000	$43.18/$53.18/$76.26
	Crude oil	10/2016 to 12/2016	550,000	$43.18/$53.18/$76.26
Collars	Crude oil	01/2015 to 03/2015	9,000	$85.00/$102.75
	Crude oil	04/2015 to 06/2015	9,100	$85.00/$102.75
	Crude oil	07/2015 to 09/2015	209,200	$51.06/$57.37
	Crude oil	10/2015 to 12/2015	209,200	$51.06/$57.37
	Crude oil	01/2016 to 03/2016	250,000	$51.00/$63.48
	Crude oil	04/2016 to 06/2016	250,000	$51.00/$63.48
	Crude oil	07/2016 to 09/2016	250,000	$51.00/$63.48
	Crude oil	10/2016 to 12/2016	250,000	$51.00/$63.48
	Crude oil	01/2017 to 03/2017	250,000	$53.00/$70.44
	Crude oil	04/2017 to 06/2017	250,000	$53.00/$70.44
	Crude oil	07/2017 to 09/2017	250,000	$53.00/$70.44
	Crude oil	10/2017 to 12/2017	250,000	$53.00/$70.44
Swaps	Crude oil	01/2015 to 03/2015	335,700	$93.33
	Crude oil	04/2015 to 06/2015	339,430	$93.33
	Crude oil	07/2015 to 09/2015	259,160	$76.57
	Crude oil	10/2015 to 12/2015	251,230	$76.25

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(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Fixed-differential Crude Oil Contracts. We have entered into two fixed-differential crude oil sales and delivery contracts for oil volumes we plan to produce from the Niobrara in Colorado.

The table below summarizes the future production volumes to be sold under one of these contracts as of January 1, 2015 at a price equal to NYMEX less a fixed differential of $4.75 per Bbl. When we are unable to deliver the production volumes specified in this contract, the fixed differential increases proportionately.

Commodity	Period	Daily Volume (Bbl per day)
Crude oil	04/2015 to 12/2015	25,000
Crude oil	01/2016 to 12/2016	28,750
Crude oil	01/2017 to 12/2017	33,750
Crude oil	01/2018 to 12/2018	38,750
Crude oil	01/2019 to 12/2019	43,750
Crude oil	01/2020 to 03/2020	45,000

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The table below summarizes the future production volumes to be sold under the second contract as of January 1, 2015 at a price equal to NYMEX less certain fixed differentials depending on the delivery methods specified in the contract.

Commodity	Period	Daily Volume (Bbl per day)
Crude oil	04/2015 to 12/2015	20,000
Crude oil	01/2016 to 12/2016	20,000
Crude oil	01/2017 to 12/2017	20,000
Crude oil	01/2018 to 12/2018	20,000
Crude oil	01/2019 to 12/2019	20,000
Crude oil	01/2020 to 03/2020	20,000

As of December 31, 2014, we determined that it is no longer probable that future oil production from our Redtail field will be sufficient to meet the minimum volume requirements specified in these fixed-differential crude oil contracts, and accordingly, that we will not settle these contracts through physical delivery of crude oil volumes. As a result, we have determined that these contracts no longer qualify for the "normal purchase normal sale" exclusion, and we have therefore reflected these contracts at fair value in the consolidated financial statements. For these commodity derivative contracts, a hypothetical $10.00 per Bbl increase in the market differential for crude oil as of December 31, 2014 would cause an increase in our commodity derivative (gain) loss of $42 million, whereas a hypothetical $10.00 per Bbl decrease in the market differential for crude oil would cause a decrease in our commodity derivative (gain) loss of $43 million.

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. At December 31, 2014, our outstanding principal balance under our credit agreement was $1.4 billion, and the weighted average interest rate on the outstanding principal balance was 1.9%. At December 31, 2014, the carrying amount approximated fair market value. Assuming a constant debt level of $1.4 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $14 million over a 12-month time period. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Notes or Senior Subordinated Notes, but interest rates do affect the fair values of our Senior Notes and Senior Subordinated Notes.

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Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation

Denver, Colorado

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado

February 27, 2015

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WHITING PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share data)

	December 31, 2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 78,100	$ 699,460
Accounts receivable trade, net	543,172	341,177
Derivative assets	135,577	1,274
Prepaid expenses and other	86,150	27,707
Total current assets	842,999	1,069,618
Property and equipment:		
Oil and gas properties, successful efforts method	14,949,702	10,065,150
Other property and equipment	276,582	206,385
Total property and equipment	15,226,284	10,271,535
Less accumulated depreciation, depletion and amortization	(3,083,572)	(2,676,490)
Total property and equipment, net	12,142,712	7,595,045
Goodwill	875,676	-
Debt issuance costs	53,274	48,530
Other long-term assets	104,843	120,277
TOTAL ASSETS	$ 14,019,504	$ 8,833,470
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 62,664	$ 107,692
Accrued capital expenditures	429,970	158,739
Revenues and royalties payable	254,018	198,558
Current portion of Production Participation Plan liability	113,391	73,264
Accrued liabilities and other	169,193	144,327
Taxes payable	63,822	50,052
Accrued interest	67,913	44,405
Deferred income taxes	47,545	648
Total current liabilities	1,208,516	777,685
Long-term debt	5,628,782	2,653,834
Deferred income taxes	1,230,630	1,278,030
Production Participation Plan liability	-	87,503

Asset retirement obligations	167,741	116,442
Deferred gain on sale	60,305	79,065
Other long-term liabilities	20,486	4,212
Total liabilities	8,316,460	4,996,771
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 300,000,000 shares authorized; 168,346,020 issued and 166,889,152 outstanding as of December 31, 2014 and 120,101,555 issued and 118,657,245 outstanding as of December 31, 2013	168	120
Additional paid-in capital	3,385,094	1,583,542
Retained earnings	2,309,712	2,244,905
Total Whiting shareholders' equity	5,694,974	3,828,567
Noncontrolling interest	8,070	8,132
Total equity	5,703,044	3,836,699
TOTAL LIABILITIES AND EQUITY	$ 14,019,504	$ 8,833,470

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share data)

	Year Ended December 31, 2014	2013	2012
REVENUES AND OTHER INCOME:			
Oil, NGL and natural gas sales	$ 3,024,617	$ 2,666,549	$ 2,137,714
Gain (loss) on hedging activities	-	(1,958)	2,338
Amortization of deferred gain on sale	30,494	31,737	29,458
Gain on sale of properties	27,657	128,648	3,423
Interest income and other	2,329	3,409	519
Total revenues and other income	3,085,097	2,828,385	2,173,452
COSTS AND EXPENSES:			
Lease operating	496,925	430,221	376,424
Production taxes	253,008	225,403	171,625
Depreciation, depletion and amortization	1,089,545	891,516	684,724
Exploration and impairment	854,430	453,210	166,972
General and administrative	177,211	137,994	108,573
Interest expense	170,642	112,936	75,210
Loss on early extinguishment of debt	-	4,412	-
Change in Production Participation Plan liability	-	(6,980)	13,824
Commodity derivative (gain) loss, net	(100,579)	7,802	(85,911)
Total costs and expenses	2,941,182	2,256,514	1,511,441
INCOME BEFORE INCOME TAXES	143,915	571,871	662,011
INCOME TAX EXPENSE (BENEFIT):			
Current	2,625	986	(669)
Deferred	76,545	204,882	248,581
Total income tax expense	79,170	205,868	247,912
NET INCOME	64,745	366,003	414,099
Net loss attributable to noncontrolling interests	62	52	90
	64,807	366,055	414,189

NET INCOME AVAILABLE TO SHAREHOLDERS			
Preferred stock dividends	-	(538)	(1,077)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 64,807	$ 365,517	$ 413,112
EARNINGS PER COMMON SHARE:			
Basic	$ 0.53	$ 3.09	$ 3.51
Diluted	$ 0.53	$ 3.06	$ 3.48
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	122,138	118,260	117,601
Diluted	122,519	119,588	119,028

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2014	2013	2012
NET INCOME	$ 64,745	$ 366,003	$ 414,099
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
OCI amortization on de-designated hedges (1) (2)	-	1,236	(1,476)
Total other comprehensive income (loss), net of tax	-	1,236	(1,476)
COMPREHENSIVE INCOME	64,745	367,239	412,623
Comprehensive loss attributable to noncontrolling interest	62	52	90
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 64,807	$ 367,291	$ 412,713

(1) Presented net of income tax expense of $722 for the year ended December 31, 2013 and an income tax benefit of $862 for the year ended December 31, 2012.

(2) These OCI amortization amounts on de-designated hedges are reclassified from accumulated other comprehensive income (“AOCI”) to gain (loss) on hedging activities in the consolidated statements of income.

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31, 2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 64,745	$ 366,003	$ 414,099
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,089,545	891,516	684,724
Deferred income tax expense	76,545	204,882	248,581
Amortization of debt issuance costs and debt premium	11,984	12,405	9,518
Stock-based compensation	23,258	22,436	18,190
Amortization of deferred gain on sale	(30,494)	(31,737)	(29,458)
Gain on sale of properties	(27,657)	(128,648)	(3,423)
Undeveloped leasehold and oil and gas property impairments	767,627	358,455	107,855
Exploratory dry hole costs	26,327	28,725	18,428
Loss on early extinguishment of debt	-	4,412	-
Change in Production Participation Plan liability	-	(6,980)	13,824
Non-cash portion of derivative gains	(57,465)	(20,830)	(115,733)
Other, net	(9,030)	(16,118)	(18,708)
Changes in current assets and liabilities:			
Accounts receivable trade, net	17,618	(22,912)	(55,750)
Prepaid expense and other	(50,352)	(15,981)	2,535
Accounts payable trade and accrued liabilities	(86,480)	33,360	58,647
Revenues and royalties payable	(1,963)	48,988	45,798
Taxes payable	1,094	16,769	2,088
Net cash provided by operating activities	1,815,302	1,744,745	1,401,215
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and development capital expenditures	(2,842,837)	(2,349,819)	(2,050,029)
Acquisition of oil and gas properties, net of cash acquired	(45,573)	(422,923)	(125,282)
Other property and equipment	(79,955)	(45,304)	3,852
Proceeds from sale of oil and gas properties	107,848	968,606	69,190
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	-	-	322,257
Issuance of note receivable	-	(10,530)	(306)
Cash paid for investing derivatives	-	(44,900)	-
Cash settlements received on investing derivatives	-	2,371	-
Net cash used in investing activities	(2,860,517)	(1,902,499)	(1,780,318)
CASH FLOWS FROM FINANCING ACTIVITIES:			

Issuance of 5% Senior Notes due 2019	-	1,100,000	-
Issuance of 5.75% Senior Notes due 2021	-	1,204,000	-
Redemption of 7% Senior Subordinated Notes due 2014	-	(253,988)	-
Borrowings under credit agreement	2,150,000	1,860,000	2,340,000
Repayments of borrowings under credit agreement	(1,675,000)	(3,060,000)	(1,920,000)
Repayment of tax sharing liability	(26,373)	(1,759)	(2,329)
Debt issuance costs	(14,901)	(29,690)	(2,807)
Restricted stock used for tax withholdings	(11,652)	(5,611)	(5,695)
Proceeds from stock options exercised	1,781	-	-
Preferred stock dividends paid	-	(538)	(1,077)
Net cash provided by financing activities	$ 423,855	$ 812,414	$ 408,092

See notes to consolidated financial statements. (Continued)

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2014	2013	2012
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ (621,360)	$ 654,660	$ 28,989
CASH AND CASH EQUIVALENTS:			
Beginning of period	699,460	44,800	15,811
End of period	$ 78,100	$ 699,460	$ 44,800
SUPPLEMENTAL CASH FLOW DISCLOSURES:			