WHITING PETROLEUM CORP
Form 10-K
February 28, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2012

or

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

For the transition period from _______________ to _______________

Commission file number: 001-31899

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

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

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

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

(Title of Class)	(Name of each exchange on which registered)
6.25% Convertible Perpetual Preferred Stock, $0.001 par value	New York Stock Exchange
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.YesT 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 T

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 T 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 T 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. T

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 filerT 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 T

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2012: $4,845,579,443.

Number of shares of the registrant's common stock outstanding at February 15, 2013: 117,829,366 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2013 Annual Meeting of Stockholders are incorporated by reference into Part III.

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GLOSSARY OF CERTAIN DEFINITIONS

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

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

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

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

"Bcf" One billion cubic feet of natural gas.

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

"CO2" Carbon dioxide.

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

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

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

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

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

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

"exploratory well" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

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

"FASB" Financial Accounting Standards Board.

"FASB ASC" The Financial Accounting Standards Board Accounting Standards Codification.

"field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

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

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

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

"LIBOR" London interbank offered rate.

"MBbl" One thousand barrels of oil or other liquid hydrocarbons.

"MBbl/d" One MBbl per day.

"MBOE" One thousand BOE.

"MBOE/d" One MBOE per day.

"Mcf" One thousand cubic feet of natural gas.

"MMBbl" One million Bbl.

"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

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

"NGL" Natural gas liquid.

"NYMEX" The New York Mercantile Exchange.

"PDNP" Proved developed nonproducing reserves.

"PDP" Proved developed producing reserves.

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

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

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

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

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

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

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

a. The area identified by drilling and limited by fluid contacts, if any, and

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

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“PUD” Proved undeveloped reserves.

“reasonable certainty” If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

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

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

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

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

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

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

“SEC” The United States Securities and Exchange Commission.

“service well” A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for in-situ combustion.

“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.

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“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, Permian Basin, Mid-Continent, Michigan and Gulf Coast regions of the United States. We were incorporated in 2003 in connection with our initial public offering.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2012, our estimated proved reserves totaled 378.8 MMBOE, representing a 10% increase in our proved reserves since December 31, 2011. Our 2012 average daily production was 82.5 MBOE/d and implies an average reserve life of approximately 12.6 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2012, their corresponding pre-tax PV10% values, and our fourth quarter 2012 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2012:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (In millions)	4th Quarter 2012 Average Daily Production (MBOE/d)
Rocky Mountains	154.0	17.9	139.8	195.2	79%	$ 4,488.9	63.0
Permian Basin	103.7	15.9	25.1	123.8	84%	1,731.9	11.0
Mid-Continent	40.9	4.9	20.4	49.2	83%	969.4	8.1
Michigan	1.7	1.2	28.1	7.6	22%	62.0	2.7
Gulf Coast	1.0	0.2	10.9	3.0	33%	31.7	1.3
Total	301.3	40.1	224.3	378.8	80%	$ 7,283.9	86.1
Discounted Future Income Taxes	-	-	-	-	-	(1,876.9)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-	-	$ 5,407.0	-

(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, 2012, 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.

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

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Our growth plan is centered on the following activities:

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

During 2012, we incurred $2,113.8 million in exploration, development and cash acquisition capital expenditures, including $1,951.7 million for the drilling of 397 gross (192.9 net) wells. Of these new wells, 188.2 (net) resulted in productive completions and 4.7 (net) were unsuccessful, yielding a 98% success rate.

Our current 2013 E&D budget is $2,200.0 million, and included in this amount is approximately $108.0 million in acreage acquisition costs. The 2013 budget of $2,200.0 million represents a 4% increase from the $2,111.5 million in E&D (which consisted of exploration, development and acreage expenditures) we incurred in 2012. We expect to fund substantially all of our 2013 E&D budget using net cash provided by operating activities, borrowings under our credit facility and certain oil and gas property divestitures. We sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Acquisitions and Divestitures

The following is a summary of our acquisitions and divestitures during the last two years. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information on these acquisitions and divestitures.

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

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

On March 28, 2012, we completed an initial public offering of units of beneficial interest in Whiting USA Trust II ("Trust II"), selling 18,400,000 Trust II units at $20.00 per unit, which generated net proceeds of $322.3 million after underwriters' fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of $128.2 million.

Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to Trust II in exchange for 100% of the trust's units issued, or 18,400,000 units. The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II's right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest. The conveyance of the net profits interest to Trust II consisted entirely of proved reserves of 10.61 MMBOE as of the January 1, 2012 effective date, representing 3% of our proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of our March 2012 average daily net production.

2011 Acquisitions. On July 28, 2011, we completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks prospect in Richland County, Montana for an unadjusted purchase price of $46.9 million.

On March 18, 2011, we formed Sustainable Water Resources, LLC ("SWR") with an unrelated third party to develop a water project in the state of Colorado. We contributed $25.0 million for a 75% interest in SWR, and the 25% noncontrolling interest in SWR was ascribed a fair value of $8.3 million, which consisted of $2.5 million in cash contributions, as well as $5.8 million in intangible and fixed assets contributed to the joint venture.

On February 15, 2011, we completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in Billings and Stark counties, North Dakota, for an aggregate purchase price of $40.0 million.

2011 Divestitures. On September 29, 2011, we sold our interest in several non-core oil and gas producing properties located in the Karnes, Live Oak and DeWitt counties of Texas for total cash proceeds of $64.8 million, resulting in a pre-tax gain on sale of $12.3 million. We used the net proceeds from the property sale to repay a portion of the debt outstanding under our credit agreement.

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 exploit and develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin project has become one of our central objectives. As of December 31, 2012, we have assembled approximately 1,109,200 gross (703,700 net) developed and undeveloped acres in the Williston Basin located in Montana and North Dakota. As of December 31, 2012, we had 20 drilling rigs operating in the Williston Basin. During 2012, the focus of our development has expanded beyond the Sanish field to include several additional areas in the Williston Basin such as the Lewis & Clark/Pronghorn, Hidden Bench/Tarpon, Missouri Breaks and Cassandra prospects. We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 30 MMcf/d and which primarily processes production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d, and as of December 31, 2012 the plant was processing 18 MMcf/d. In November 2012, we began connecting other operators' wells to the plant. We intend to add inlet compression during 2013 in order to fully utilize the 30 MMcf/d processing capability. We are also currently installing fractionation equipment to convert NGLs into propane and butane, which end products are typically sold for higher realized prices in local markets. Additionally, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn prospect into the Bridger Four Bears oil transmission system. The use of this terminal will reduce our transportation costs per barrel and thereby increase our returns on the development of this prospect.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past five years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2012, we have identified a drilling inventory of over 2,400 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 non-proved reserves. Additionally, we have several 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 two large oil fields, the Postle field, located in the Oklahoma Panhandle, and the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced significant production increases to date in these fields through the use of secondary and tertiary recovery techniques, and we anticipate such production increases at the North Ward Estes field to continue over the next four to five years. In these fields, 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 over 300 MMcf/d of recycled CO_2 and thereby maximize our recovery of oil and gas from these reservoirs.

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Growing Through Accretive Acquisitions. From 2004 to 2012, we completed 16 separate significant acquisitions of producing properties for estimated proved reserves of 230.9 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, closing purchases and then effectively managing properties we acquire. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings, internally generated cash flow and certain oil and gas divestitures, as appropriate, to maintain our strong financial position. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and fixed price gas contracts to provide an attractive base commodity price level.

Competitive Strengths

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

Balanced, Long-Lived Asset Base. As of December 31, 2012, we had interests in 10,218 gross (3,927 net) productive wells across approximately 1,277,400 gross (680,300 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities to execute our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 12.6 years based on year-end 2012 proved reserves and 2012 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 32 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 detailed 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 7,224 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. With the acquisition of the Postle and North Ward Estes properties, we have assembled a team of 12 professionals averaging over 24 years of expertise managing CO_2 floods. This 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 our in-house rock analysis laboratory. This state-of-the-art facility includes two scanning electron microscopes ("SEM"), and these SEMs enable rapid turnaround analysis of drilling or cored wells designed to support real-time drilling and completion decisions. These SEMs also allow us to quantify porosity networks, which in turn helps our staff comparatively evaluate producing zones in present and future plays under consideration. In addition, having SEMs in-house allows our team of experts to analyze samples more rapidly than an outside service company would and with the full operational context that only full-time employees possess, while protecting our proprietary data. Furthermore, we have established a two-room core layout facility capable of displaying several hundred feet of core slabs under plain or ultraviolet light. The ability for multidisciplinary groups such as geoscientists, operations personnel, reservoir engineers, drilling engineers and senior management to discuss technical issues over the displayed cores has helped us become a leader in tight oil play exploration and development.

Over the past few years, we utilized our "Drill Well on Paper" optimization process to significantly reduce the number of days it takes to drill a well. Due to the success of this program, in September 2012 we expanded the concept using a program called "Build-to-POP." The objective of this program is to optimize the process from the time we build a drilling location to the time we put a well on production ("POP"), to reduce our overall cycle time. Early results have reduced the time from spud to POP from just under 91 days per well to approximately 67 days per well. We have realized similar results in the amount of time required to move a rig from one location to the next. Our rig move times have dropped from approximately nine days to just over seven days. We plan to take what we learn with this project in the Williston Basin and apply the process to our Redtail prospect in Colorado.

As the Bakken project in the Williston Basin matures and wells are drilled across large areas of the Williston Basin, we have assembled a more comprehensive database of information. This provides the opportunity to apply more scientific analysis of the data and to develop tools to assist our petro-technical staff with well and completion designs. In mid-2012, we initiated a study with a major service provider to review, analyze and make refinements to our fracture stimulations. Results from this study have enhanced our ability to numerically model fracture stimulations and to make refinements to increase the effectiveness of these stimulations and improve well performance.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2012 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:	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (In millions)
PDP	98.0	11.9	94.5	125.7	65%	
PDNP	0.4	0.2	1.4	0.8	-%	
PUD	55.6	5.8	43.9	68.7	35%	
Total Proved	154.0	17.9	139.8	195.2	100%	$ 1,645.0
Total Probable	43.7	3.2	42.2	53.9		$ 1,408.3
Total Possible	43.3	4.3	117.4	67.1		$ 1,478.7
Permian Basin:						
PDP	44.2	4.2	12.1	50.4	41%	
PDNP	15.8	3.0	2.3	19.2	15%	
PUD	43.7	8.7	10.7	54.2	44%	
Total Proved	103.7	15.9	25.1	123.8	100%	$ 1,136.3
Total Probable	27.6	6.6	43.6	41.5		$ 560.0
Total Possible	78.2	17.5	9.6	97.3		$ 966.7
Mid-Continent:						
PDP	29.0	3.8	17.0	35.6	72%	
PDNP	0.9	0.1	0.5	1.1	2%	
PUD	11.0	1.0	2.9	12.5	26%	
Total Proved	40.9	4.9	20.4	49.2	100%	$ 375.7
Total Probable	11.0	1.5	3.9	13.2		$ 147.8
Total Possible	0.1	-	-	0.1		$ 0.4
Michigan:						
PDP	1.0	0.5	16.3	4.2	55%	
PDNP	0.6	0.3	6.0	1.9	25%	
PUD	0.1	0.4	5.8	1.5	20%	
Total Proved	1.7	1.2	28.1	7.6	100%	$ 17.2
Total Probable	1.9	0.2	9.8	3.7		$ 32.3
Total Possible	0.5	0.1	9.2	2.2		$ 16.0
Gulf Coast:						
PDP	0.9	0.2	8.6	2.5	83%	
PDNP	0.1	-	2.2	0.5	17%	
PUD	-	-	0.1	-	-%	
Total Proved	1.0	0.2	10.9	3.0	100%	$ 7.4
Total Probable	0.8	0.4	10.1	2.9		$ 27.9
Total Possible	1.1	-	20.2	4.5		$ 71.6

Total Company:						
PDP	173.1	20.6	148.5	218.4	58%	
PDNP	17.8	3.6	12.4	23.5	6%	
PUD	110.4	15.9	63.4	136.9	36%	
Total Proved	301.3	40.1	224.3	378.8	100%	$ 3,181.6
Total Probable	85.0	11.9	109.6	115.2		$ 2,176.3
Total Possible	123.2	21.9	156.4	171.2		$ 2,533.4

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The estimated future capital expenditures in the table above incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. The table below presents percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2012, 2011 and 2010. 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.

	2012	2011	2010
Plains Marketing LP (1)	20%	27%	16%
Shell Trading US	14%	13%	17%
Nexen Pipeline USA, Inc. (1)	-	-	13%
Eighty Eight Oil Company	11%	8%	4%
Bridger Trading LLC	11%	6%	5%
EOG Resources, Inc.	4%	7%	10%

(1) Effective December 30, 2010, Plains Marketing LP acquired Nexen Pipeline USA, Inc.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties in 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 capital available for investment 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 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 uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

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

We cannot accurately predict whether the FERC’s actions will achieve the goal of increasing competition in 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. The natural gas industry historically has been very 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 PIPES Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. The Pipeline and Hazardous Material Safety Administration (“PHMSA”), an agency with the DOT, enforces regulations on interstate natural gas transportation. Intrastate natural gas transportation is subject to enforcement by state regulatory agencies. 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 under 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. 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 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 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. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

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

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing and 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 at which 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 ("BOEM"). Currently, only 0.1% of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was $30.8 million as of December 31, 2012. Whiting is therefore required to comply with the regulations and orders issued by 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 approval 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, BOEM could require us to suspend or terminate our operations on a federal lease.

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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 BOEM and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

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

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 the 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.

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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 $350.0 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75.0 million per spill damages. These limits do not apply if the spill is caused by a responsible party’s gross negligence or willful misconduct; the spill resulted from a responsible party’s violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President may increase the amount of financial responsibility required under OPA by up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA’s financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. We generate solid and hazardous wastes that are subject to RCRA and comparable state laws. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA, requesting them to reconsider the RCRA exemption for exploration, production and development wastes but, to date, the agency has not taken any action on the petition. The EPA has not formally responded to this petition yet. Any such change in the current RCRA exemption and comparable state laws, could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes may be regulated by state agencies as solid waste. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes as they are presently classified to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

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

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

Air Emissions. The federal Clean Air Act (the "CAA"), as amended, 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, on April 17, 2012, the EPA finalized rules that would establish 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 would require the application of reduced emission completion techniques for 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.

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Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. Hydraulic fracturing has been utilized in the completion of wells we have drilled, and we expect it will also be used in the future. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently took the position that hydraulic fracturing operations using diesel are subject to regulation under the Underground Injection Control program of the Safe Drinking Water Act as Class II wells and has commenced drafting guidance for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel. Industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release the final results by 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy ("DOE"), the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior is also considering regulation of hydraulic fracturing activities on public lands. In addition, the Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements 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) 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 and potential increases in costs. Further, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities. Moreover, we believe that enactment of legislation regulating hydraulic fracturing at the federal level may have a material adverse effect on our business.

Global Warming and Climate Change. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the CAA, including one rule that limits emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011. We believe that we are in compliance with all substantial applicable emissions requirements, and we are preparing to comply with future requirements.

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

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, 2012, we had 829 full-time employees, including 33 senior level geoscientists and 71 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 Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission.

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Item 1A. Risk Factors

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

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

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

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, such as recent conflicts in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the effects of global credit, financial and economic issues;
- the level of global oil and natural gas inventories;
- developments of United States energy infrastructure, such as the recent announcement of the planned reversal of the Seaway pipeline from Cushing, Oklahoma to the Gulf Coast and the development of liquefied natural gas exporting facilities and the perceived timing thereof;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- the price and availability of alternative fuels; and
- acts of force majeure.

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

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis but also may ultimately reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve quantities. A substantial or extended decline in oil, NGL or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil, NGL and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

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

Our future success will depend on the success of our development, exploitation, production and exploration 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;
- 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.

Federal and state 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 formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of Colorado, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act's Underground Injection Control Program and has commenced drafting guidance for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel. Industry groups have filed suit challenging the EPA's recent decision.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release the final results by 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the DOE, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior is also considering regulation of hydraulic fracturing activities on public lands. In addition, legislation called the FRAC Act has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements 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) 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, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. 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 or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states where our properties are located, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities.

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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 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, 2012, proved undeveloped reserves comprised 43% of the North Ward Estes field’s total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $750.0 million at the North Ward Estes field as of December 31, 2012. This field encompasses 28% 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 CO_2 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 which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

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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 $3.2 million impairment write-down during 2011 for the partial impairment of producing properties, primarily natural gas, in California and Michigan. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period recognized.

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

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

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

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

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

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2012 would have decreased from $5,407.0 million to $5,398.9 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, 2012 would have decreased from $5,407.0 million to $5,312.0 million.

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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 exploit 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 and state legislative and regulatory initiatives relating to hydraulic fracturing..." above in these Risk Factors for a discussion of the uncertainty involved in the practice of hydraulic fracturing. In addition, curtailments or damage to pipelines used to transport oil, NGLs and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailment 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, drilling, production and transportation of hydrocarbons bear an inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water, and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

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

As of December 31, 2012, we had $1,200.0 million in borrowings and $2.4 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with $797.6 million of available borrowing capacity, as well as $600.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's 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;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation's credit agreement is subject to certain rate variability; and
- potentially limiting our ability to pay dividends in cash on our convertible perpetual preferred stock.

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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 will 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 Corporation's credit agreement is periodically redetermined based on an evaluation of our oil and gas reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt 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 Corporation's credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

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

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's 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 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 Corporation's 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for the quarters ending March 31, 2013 and thereafter 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 subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

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If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas Corporation's 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 and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations, existing financing arrangements and certain oil and gas divestitures. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

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

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.

The global recession and tight financial markets may have impacts on our business and financial condition that we currently cannot predict.

The current global recession and tight credit financial markets may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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Our acquisition activities may not be successful.

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

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

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

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

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

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Additionally, our operations in some instances require supply materials such as CO_2 for production 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, 2012, we had identified a drilling inventory of over 2,400 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, 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 adversely affect our business.

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

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2010, we recorded a $5.8 million non-cash charge for the impairment of unproved properties in the central Utah Hingeline play. 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 2012, we completed 16 separate significant acquisitions of producing properties with a combined purchase price of $1,900.3 million for estimated proved reserves as of the effective dates of the acquisitions of 230.9 MMBOE. The successful acquisition of producing properties requires assessments 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
- potential environmental and other liabilities.

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.

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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 forward sales contracts, primarily costless collars, placed with major financial institutions. As of February 6, 2013, we had contracts, which include our 10% share of the Whiting USA Trust II hedges, covering the sale of between 1,044,340 and 1,334,550 barrels of oil per month for all of 2013. All of our oil hedges will expire by December 2014. See "Quantitative and Qualitative Disclosure about Market Risk" in Item 7A of this Annual Report on Form 10-K for pricing and a more detailed discussion of our hedging transactions.

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

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

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

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

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

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, 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.

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Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. For example, as a result of the explosion and fire on the Deepwater Horizon drilling rig in April 2010 and the release of oil from the Macondo well in the Gulf of Mexico, there has been a variety of governmental regulatory initiatives to make more stringent or otherwise restrict oil and natural gas drilling operations in certain locations. 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 gasses” could result in increased operating costs and reduced demand for oil and gas that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency (the “EPA”) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act (the “CAA”), including one rule that limits emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. This rule “tailors” these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining “best available control technology” standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

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

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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 development, exploitation and exploration 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 exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

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

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, Chairman and Chief Executive Officer; James T. Brown, President and Chief Operating Officer; Mark R. Williams, Senior Vice President, Exploration and Development; J. Douglas Lang, Vice President, Reservoir Engineering/Acquisitions; Rick A. Ross, Vice President, Operations; David M. Seery, Vice President, Land; Michael J. Stevens, Vice President and Chief Financial Officer; or Peter W. Hagist, Vice President, Permian Operations, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources 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 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.

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 2012, President Obama's Administration released its proposed federal budget for fiscal year 2013 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 certain U.S. 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.

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

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming and California. As of December 31, 2012, our estimated proved reserves in the Rocky Mountain region were 195.2 MMBOE (79% oil), which represented 51% of our total estimated proved reserves and contributed 67.6 MBOE/d of average daily production in December 2012.

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses approximately 107,800 gross (66,100 net) developed and undeveloped acres. Net production in the Sanish field averaged 32.6 MBOE/d for the fourth quarter of 2012, representing a 4% increase from 31.4 MBOE/d in the third quarter of 2012. As of December 31, 2012, we had seven drilling rigs active in the Sanish field. Two of these rigs are drilling multiple wells from the same drilling location or well pad ("pad drilling"). We plan to initiate a higher density pilot program in the Sanish field in the first half of 2013. We also plan to re-fracture stimulate several wells in our Sanish field in 2013.

In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake gas plant. In December 2010, we added additional equipment which brought the plant's processing capacity to 90 MMcf/d. In April 2011, we added fractionation equipment which allows us to produce propane and butane, which end products are typically sold for higher realized prices in local markets. Additionally, we added compression in September 2012 that brought the plant's inlet capacity to 72 MMcf/d, and we intend to add field compression during 2013 in order to fully utilize the 90 MMcf/d processing capability.

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Lewis & Clark/Pronghorn. Our Lewis & Clark/Pronghorn prospects are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). As of December 31, 2012, the Lewis & Clark/Pronghorn prospects encompassed approximately 398,300 gross (263,000 net) developed and undeveloped acres. Net production in the Lewis & Clark/Pronghorn prospects averaged 13.4 MBOE/d in the fourth quarter of 2012, representing a 10% increase from 12.2 MBOE/d in the third quarter of 2012. As of December 31, 2012, we had seven drilling rigs operating in the Pronghorn prospect, making this our second most active area in the Williston Basin. Four of the rigs working in the Pronghorn prospect are utilizing pad drilling, drilling two or three wells from each pad. We are realizing cost efficiencies with the use of multi-well pads in the drilling and completion of wells. We also plan to conduct a higher density pilot program in the Pronghorn prospect in 2013.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 30 MMcf/d and which primarily processes production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d, and as of December 31, 2012 the plant was processing 18 MMcf/d. In November 2012, we began connecting other operators' wells to the plant. We intend to add inlet compression during 2013 in order to fully utilize the 30 MMcf/d processing capability. We are also currently installing fractionation equipment to convert NGLs into propane and butane, which end products are typically sold for higher realized prices in local markets. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and will continue to operate the Belfield plant and facilities. Additionally, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn prospect into the Bridger Four Bears oil transmission system. The use of this terminal will reduce our transportation costs per barrel and thereby increase our returns on the development of this prospect.

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations and encompass approximately 49,100 gross (28,600 net) developed and undeveloped acres and 8,100 gross (6,300 net) developed and undeveloped acres, respectively, as of December 31, 2012. Net production at Hidden Bench/Tarpon averaged 3.1 MBOE/d in the fourth quarter of 2012, which represents a 23% increase from 2.5 MBOE/d in the third quarter of 2012. We drilled a highly productive Tarpon Federal well in late 2011 in the Tarpon prospect. Based on the results, we had planned to drill additional wells in Tarpon but were delayed by federal drilling permit requirements for these wells. During the fourth quarter of 2012, we received the required permits and drilled four additional wells in this area. We expect to drill most of the remaining planned Tarpon development wells during 2013. We have implemented pad drilling at our Tarpon prospect and plan to drill three wells from each pad.

Missouri Breaks Prospect. As of December 31, 2012, we had approximately 95,900 gross (66,100 net) developed and undeveloped acres at our Missouri Breaks prospect located in Richland County, Montana and McKenzie County, North Dakota. In the fourth quarter of 2012, net production from the Missouri Breaks prospect averaged 1.7 MBOE/d, representing a 189% increase from 0.6 MBOE/d in the third quarter of 2012. We have drilled successful wells on the western and southern portions of our acreage. In the fourth quarter of 2012, we completed our first well on the eastern portion of our Missouri Breaks prospect.

Big Island Prospect. As of December 31, 2012, we had approximately 172,500 gross (122,400 net) developed and undeveloped acres at our Big Island prospect, which is located in Golden Valley County, North Dakota and Wibaux County, Montana. We are using 3-D seismic interpretations to identify Red River drilling locations at our Big Island prospect. We plan to use a horizontal well to test the Lower Red River "D" zone in 2013.

Redtail Prospect. As of December 31, 2012, we had approximately 109,900 gross (79,500 net) developed and undeveloped acres at our Redtail prospect in the Weld County, Colorado portion of the Denver Julesburg Basin. In 2012, we drilled 15 wells in this prospect and were very encouraged with the results. We plan to drill up to eight Niobrara "B" wells per spacing unit and utilize pad drilling to place the wells. The associated gas produced along with Niobrara crude oil must be processed before being sold, and we have therefore initiated the construction of our own gas processing plant in Weld County, Colorado for this purpose. The plant's planned inlet capacity will be 15 MMcf/d. The air permit for the plant was filed with the Colorado Department of Public Health and Environment in November 2012. We have ordered the major equipment necessary to construct this plant, and we plan to have the plant online in early 2014. As of December 31, 2012, we had one drilling rig operating in this area, and we plan to add a second drilling rig in mid-year 2013 and a third upon completion of the plant.

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Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2012, the Permian Basin region contributed 123.8 MMBOE (84% oil) of estimated proved reserves to our portfolio of operations, which represented 33% of our total estimated proved reserves and contributed 11.0 MBOE/d of average daily production in December 2012.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interests in approximately 62,100 gross (60,400 net) developed and undeveloped acres in Ward and Winkler counties, Texas. Current EOR production 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. In the North Ward Estes field, the estimated proved reserves as of December 31, 2012 were 41% PDP, 16% PDNP and 43% PUD.

The North Ward Estes field has been responding positively to our water and CO_2 floods that we initiated in May 2007. In the fourth quarter of 2012, production from the field averaged 8.5 MBOE/d, which was consistent with production rates in the third quarter of 2012. As of December 31, 2012, we were injecting approximately 350 MMcf/d of CO_2 in this field, over half of which is recycled. In this field, we are developing new and reactivated wells for water and CO_2 injection and for production purposes. Additionally, we plan to install oil, gas and water processing facilities in eight phases. The first three phases are essentially complete and are currently undergoing water and CO_2 injection. The field and injection infrastructure of Phase IV is complete, and injection has been initiated on about half of the project.

In order to fully develop the proved undeveloped reserves at North Ward Estes within our currently planned timeframe, we will need to utilize significant quantities of purchased CO_2. As of December 31, 2012, we currently have under contract 100% of the future CO_2 volumes that we believe are necessary to develop the field's proved undeveloped reserves. In addition, we are currently in negotiations and 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, we cannot provide absolute assurance with respect to the timing or actual quantities of CO_2 that will be obtainable for the development of oil and gas reserves at this field.

Big Tex Prospect. As of December 31, 2012, we had accumulated approximately 116,700 gross (86,900 net) developed and undeveloped acres at our Big Tex prospect in Pecos, Reeves and Ward counties, Texas in the Delaware Basin. Prospective formations include the Brushy Canyon, Bone Spring and Wolfcamp horizons. During 2013, we plan to drill three wells in the Big Tex prospect, all of which are expected to be horizontal Wolfcamp wells. In late 2012, we completed a well utilizing a cemented liner and a plug and perf completion technique that is providing encouraging early results. We plan to implement this completion strategy on the horizontal wells drilled during 2013.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2012, the Mid-Continent region contributed 49.2 MMBOE (83% oil) of proved reserves to our portfolio of operations, which represented 13% of our total estimated proved reserves and contributed 7.9 MBOE/d of average daily production in December 2012. The majority of the proved value within our Mid-Continent operations is related to properties in the Postle field.

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Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 26,400 gross (26,100 net) developed and undeveloped acres. Four of the units are currently active CO2 enhanced recovery projects. In the fourth quarter of 2012, production from the field averaged 7.8 MBOE/d, which represents a 4% decrease from 8.2 MBOE/d in the third quarter of 2012. As of December 31, 2012, we were injecting approximately 120 MMcf/d of CO2 in this field, over half of which is recycled gas. We manage our CO2 flood at Postle on a pattern-by-pattern basis in order to optimize utilization of CO2, crude oil production, and ultimate recovery. A pattern typically consists of a producing well surrounded by four water/CO2 injectors. As a pattern matures, increasing volumes of water are alternated with CO2 injection to control gas breakthrough and to optimize sweep efficiency. This process, referred to as "WAG" (Water Alternating Gas), typically results in the highest possible oil recovery. In the Postle field, the estimated proved reserves as of December 31, 2012 were 73% PDP, 2% PDNP and 25% PUD.

We are the sole owner of the Dry Trails gas plant located in the Postle field. This plant is comprised of two trains each with a processing capacity of approximately 40 MMcf/d. The more recent train, which Whiting constructed, utilizes a membrane technology to extract CO2 from the produced wellhead mixture of hydrocarbon and CO2 gas, so that it can be re-injected into the producing formation.

In addition to the producing assets and processing plant, we have a 60% interest in the 120-mile Transpetco operated CO2 transportation pipeline, thereby assuring the delivery of CO2 to the Postle field at a fair tariff. We have entered into long-term purchase agreements that will provide the necessary CO2 to carry out the flood over the life of the field.

Michigan Region

As of December 31, 2012, our estimated proved reserves in the Michigan region were 7.6 MMBOE (22% oil), which represents 2% of our total estimated proved reserves, and our December 2012 daily production averaged 2.7 MBOE/d. We also operate the West Branch and Reno gas processing plants. The West Branch plant gathers production from the Clayton unit, West Branch field and other smaller fields.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2012, the Gulf Coast region contributed 3.0 MMBOE (33% oil) of proved reserves to our portfolio of operations, which represented 1% of our total estimated proved reserves and contributed 1.2 MBOE/d of average daily production in December 2012.

Reserves

As of December 31, 2012, 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, 2012 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, 2012) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Developed	190,845	24,204	160,893	241,864
Undeveloped	110,440	15,894	63,371	136,896

Total proved—December 31, 2012	301,285	40,098	224,264	378,760
Probable reserves				
Developed	2,343	534	6,984	4,041
Undeveloped	82,639	11,388	102,598	111,127
Total probable—December 31, 2012	84,982	11,922	109,582	115,168
Possible reserves				
Developed	772	97	1,721	1,156
Undeveloped	122,407	21,839	154,661	170,022
Total possible—December 31, 2012	123,179	21,936	156,382	171,178

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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 2012, total extensions and discoveries of 81.5 MMBOE were primarily attributable to successful drilling in the Sanish field, Redtail prospect, Missouri Breaks prospect and the Pronghorn area. The new producing wells in these fields and their related proved undeveloped locations added during the year increased our proved reserves.

In 2012, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 7.1 MMBOE. Included in these revisions were (i) 11.8 MMBOE of downward adjustments caused by lower crude oil and natural gas prices incorporated into our reserve estimates at December 31, 2012 as compared to December 31, 2011 and (ii) 4.7 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

The gas component of the net 4.7 MMBOE revision consisted of a 1.1 MMBOE decrease that was primarily related to (i) a downward revision for the recent performance of various gas wells in the Central Rockies area, and (ii) performance adjustments on various oil wells in the Northern Rockies area and Permian Basin region that negatively impacted those wells' associated gas reserves. Partially offsetting these negative revisions was an increase in associated gas volumes related to additional oil reserves assigned to the Postle and North Ward Estes fields.

Proved undeveloped reserves. From December 31, 2011 to December 31, 2012, our proved undeveloped reserves ("PUDs") increased 28% or 29.9 MMBOE. This increase in proved undeveloped reserves was primarily attributable to additional PUD locations added as a result of successful drilling in the Northern and Central Rockies areas and additional PUD reserves being assigned to our Postle and North Ward Estes EOR projects. There were 16.8 MMBOE of PUDs that became proved developed reserves during the year as a result of 83 proved undeveloped well locations that were drilled and placed on production in 2012. We incurred $392.2 million in capital expenditures, or $23.33 per BOE, to drill and bring on-line these 83 PUD locations. In addition, there were approximately 7.1 MMBOE of PUDs that became proved developed reserves in 2012 at our CO2 EOR projects in the Postle and North Ward Estes fields. These PUDs were converted to proved developed at a cost of approximately $34.95 per BOE. Combining the PUD drilling conversions with the PUD enhanced oil recovery conversions, the Company converted 23.9 MMBOE of PUDs to proved developed reserves during 2012 at a cost of $26.80 per BOE.

Based on our 2012 year end independent engineering reserve report, we will drill all of our individual PUD drilling locations within five years. However, we do have certain quantities of proved undeveloped reserves in the North Ward Estes field that will remain in the PUD category for periods extending beyond five years because of certain external factors that preclude the development of the North Ward Estes enhanced oil recovery PUDs all at once. Due to the large areal extent of the field, the CO2 enhanced recovery project will progress through the field in a sequential manner as earlier injection areas are completed and new injection areas are initiated. External factors that preclude the initiation of the CO2 project throughout the field at the same time include: (i) the volume of injection water necessary to repressure 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 CO2 enhanced recovery 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.

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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 reserves 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 2012 were primarily attributable to (i) 400 new probable undeveloped well locations, which were added in 2012 as a result of our drilling activity in the Rocky Mountains region, and (ii) new probable reserve volumes in the Queen formation at North Ward Estes, that were added due to successful CO2 pilot floods that were carried out on this reservoir.

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 decreased during 2012 primarily due to successful drilling at our Sanish field, Lewis & Clark/Pronghorn prospects and Hidden Bench/Tarpon prospects, which resulted in possible reserves being promoted to either the probable or proved reserve categories in these areas.

At December 31, 2012, our probable reserves were estimated to be 115.2 MMBOE and our possible reserves were estimated to be 171.2 MMBOE, for a total of 286.3 MMBOE. The EOR project at our North Ward Estes field represented 106.8 MMBOE, or 37%, of our total 286.3 MMBOE probable and possible reserve quantities. In order to fully develop the EOR probable and possible reserves at North Ward Estes, we will need to utilize significant quantities of purchased CO2. We are currently in negotiations and planning for future sources capable of generating sufficient CO2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO2 supplies is subject to uncertainty and may require significant future capital expenditures by us, and we cannot therefore provide assurance with respect to the timing or actual quantities of CO2 that will be obtainable for the development of such reserves.

Preparation of reserves estimates. The Company maintains 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 the Company's accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in Internal Control – Integrated Framework 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. The Company's 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, Whiting's independent engineering firm Cawley, Gillespie & Associates, Inc. ("CG&A") meets with Whiting's technical personnel in the Company's 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 the Company's 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 39 years of experience, the majority of which has involved reservoir engineering and reserve estimation, holds a Bachelor's degree in petroleum engineering from the University of Wyoming, holds an MBA from the University of Denver and is a registered Professional Engineer. He has also served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2012. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross(2)	Net(2)	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	46,454	28,815	137,285	89,318	183,739	118,133
Louisiana	39,431	7,353	54,383	49,835	93,814	57,188
Michigan	141,800	63,571	9,291	6,554	151,091	70,125
Montana	61,808	33,754	204,826	151,473	266,634	185,227
North Dakota	460,297	259,780	382,232	258,660	842,529	518,440
Oklahoma	85,969	54,143	566	175	86,535	54,318
Texas	260,358	146,910	149,707	107,857	410,065	254,767
Utah	31,148	16,016	332,964	179,815	364,112	195,831

Wyoming	97,964	56,455	51,581	38,363	149,545	94,818
Other(1)	26,634	9,935	1,832	1,266	28,466	11,201
Total	1,277,411	680,338	1,324,667	883,316	2,602,078	1,563,654

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

(2) Out of a total of approximately 1,324,667 gross (883,316 net) undeveloped acres as of December 31, 2012, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is less than 12% in 2013, approximately 9% in 2014 and 21% in 2015.

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Production History

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

	Year Ended December 31,		
	2012	2011	2010
Oil production (MMBbl)	23.1	18.3	17.5
NGL production (MMBbl)	2.8	2.1	1.5
Natural gas production (Bcf)	25.8	26.4	27.4
Total production (MMBOE)	30.2	24.8	23.6
Daily production (MBOE/d)	82.5	67.9	64.6
North Ward Estes field production (1)			
Oil production (MMBbl)	2.8	2.6	2.4
NGL production (MMBbl)	0.3	0.4	0.3
Natural gas production (Bcf)	0.3	0.4	0.4
Total production (MMBOE)	3.2	3.0	2.8
Sanish field production (1)			
Oil production (MMBbl)	9.0	6.5	6.4
NGL production (MMBbl)	1.2	0.8	0.4
Natural gas production (Bcf)	3.6	2.2	2.5
Total production (MMBOE)	10.8	7.7	7.2
Average sales prices:			
Oil (per Bbl)	$83.86	$88.61	$72.61
NGLs (per Bbl)	$39.36	$52.38	$47.33
Natural gas (per Mcf)	$3.42	$4.92	$4.86
Average production costs:			
Production costs (per BOE)(2)	$11.92	$11.77	$10.62

(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, 2012.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $16.3 million ($0.54 per BOE), $13.9 million ($0.56 per BOE) and $17.7 million ($0.75 per BOE) for the years ended December 31, 2012, 2011 and 2010, respectively.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2012. 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	2,916	832	420	227	3,336	1,059
Permian Basin	4,053	1,709	390	125	4,443	1,834
Mid-Continent	598	386	184	68	782	454
Michigan	77	42	1,100	418	1,177	460
Gulf Coast	82	42	398	78	480	120
Total	7,726	3,011	2,492	916	10,218	3,927

(1) 133 wells have multiple completions. These 133 wells contain a total of 333 completions. One or more completions in the same bore hole are counted as one well.

We have an interest in or operate 35 EOR projects, which include both secondary (waterflood) and tertiary (CO_2 injection) recovery efforts, and aggregate production from such EOR fields averaged 19.1 MBOE/d during 2012 or 23% of our 2012 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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Drilling Activity

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

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2012:						
Development	324	-	324	140.4	-	140.4
Exploratory	68	5	73	47.8	4.7	52.5
Total	392	5	397	188.2	4.7	192.9
2011:						
Development	218	3	221	93.9	1.5	95.4
Exploratory	60	3	63	36.6	3.0	39.6
Total	278	6	284	130.5	4.5	135.0
2010:						
Development	163	3	166	73.8	0.7	74.5
Exploratory	20	3	23	10.5	3.0	13.5
Total	183	6	189	84.3	3.7	88.0

As of December 31, 2012, 25 operated drilling rigs were active on our properties. We were also participating in the drilling of nine non-operated wells. The breakdown of our operated rigs by region is as follows:

Region	Drilling Rigs
Rocky Mountains	22
North Ward Estes	2
Postle	1
Total	25

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 Item 1. “Business – Regulation – Environmental Regulations – Hydraulic Fracturing” of this Annual Report on Form 10-K, the EPA has initiated the regulation of hydraulic fracturing; other federal agencies are examining hydraulic fracturing; and federal legislation is pending with respect to hydraulic fracturing. We have utilized hydraulic fracturing in the completion of our wells in our most active areas located in the states of North Dakota, Colorado, Michigan, Montana and Texas, and we plan on continuing to utilize this completion methodology.

Proved undeveloped reserves associated with hydraulic fracture treatments consist of substantially all of our proved undeveloped reserves, or 136.9 MMBOE.

In November 2010, we had a well control incident involving one well in our Sanish field, whereby the North Dakota Industrial Commission (“NDIC”) filed a complaint against Whiting alleging the violation of regulations. This matter resulted in us entering into a consent agreement with the NDIC, pursuant to which we paid $4,357 in costs, donated $15,000 to the North Dakota Abandoned Oil and Gas Well Plugging and Site Reclamation Fund, and agreed to implement certain operational procedures. Other than this incident, we are not aware of any environmental incidents, citations or suits related to hydraulic fracturing operations involving oil and gas properties that we operate or our non-operated interests.

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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 NDIC or other state requirements;
- we train all company and contract personnel, who are responsible for well preparation, fracture stimulation and flowback, on our procedures;
- we have implemented the incremental procedures of running a well casing caliper; visually inspecting the surface joint of intermediate casing; and if a lighter wall joint of casing or drilling wear is detected, the minimum burst pressure is reduced accordingly;
- for wells that are within one mile of major bodies of water or locations that lead to bodies of water, we construct sufficient berming around the well location prior to initiating fracturing operations;
- we run fracturing strings in certain situations when extra precaution is warranted, such as where the anticipated maximum treating pressure for the well is greater than the pressure rating of the intermediate casing or in areas located within one mile of major bodies of water; and
- we are constructing a facility in North Dakota to treat and dispose of flow fluids from well stimulations.

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

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry, generally provide for sales based on prevailing market prices in the area, and generally have terms of one year or less. We have also entered into physical delivery contracts which require us to deliver fixed volumes of natural gas. As of December 31, 2012, we had delivery commitments of 4.4 Bcf (or 17% of total 2012 natural gas production) and 4.0 Bcf (16%) for the years ended December 31, 2013 and 2014, respectively. These contracts relate to production at our Boies Ranch field in Rio Blanco County, Colorado and our Flat Rock field in Uintah County, Utah. We believe that our production and reserves are adequate to meet these delivery commitments. See "Quantitative and Qualitative Disclosure about Market Risk" in Item 7A of this Annual Report on Form 10-K for more information about these contracts.

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 15, 2013, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	66	Chairman and Chief Executive Officer
James T. Brown	60	President and Chief Operating Officer
Mark R. Williams	56	Senior Vice President, Exploration and Development
Bruce R. DeBoer	60	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	42	Vice President, Human Resources
J. Douglas Lang	63	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	54	Vice President, Operations
David M. Seery	58	Vice President, Land
Michael J. Stevens	47	Vice President and Chief Financial Officer
Brent P. Jensen	43	Controller and Treasurer

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

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Effective January 1, 2011, Mr. Volker stepped down as President, but remains Chairman and Chief Executive Officer. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has 41 years of experience in the oil and gas industry. Mr. Volker has a Bachelor’s degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates’ course of study in reservoir engineering.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager; in January 2000, he became Vice President of Operations; and in May 2007, he became Senior Vice President. Effective January 1, 2011, Mr. Brown was elected President and Chief Operating Officer. Mr. Brown has 38 years of oil and gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming with a Bachelor’s degree in civil engineering and the University of Denver with an MBA.

Mark R. Williams joined us in December 1983 as Exploration Geologist and has been Vice President of Exploration and Development since December 1999. Mr. Williams was elected Senior Vice President, Exploration and Development effective January 1, 2011. He has 32 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 33 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 16 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts degree in anthropology and an MBA from the University of Colorado. She is a certified Senior Professional in Human Resources.

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J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager of Acquisitions and Reservoir Engineering in January 2004 and Vice President, Reservoir Engineering and Acquisitions in October 2004. His 39 years of acquisition and reservoir engineering experience has included staff and managerial positions with Amoco, Petro-Lewis, General Atlantic Resources, UMC Petroleum and Ocean Energy. Mr. Lang holds a Bachelor’s degree in petroleum engineering from the University of Wyoming and an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations. Mr. Ross has 30 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 and was a past Chairman of the North Dakota Petroleum Council.

David M. Seery joined us as our Manager of Land in July 2004 as a result of our acquisition of Equity Oil Company, where he was Manager of Land and Manager of Equity’s Exploration Department, positions he had held for more than five years. He became our Vice President of Land in January 2005. Mr. Seery has 32 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.

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 26 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 19 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 (as adjusted for the two-for-one stock split as noted below) for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2012		
Fourth Quarter (Ended December 31, 2012)	$48.87	$40.19
Third Quarter (Ended September 30, 2012)	$54.86	$38.29
Second Quarter (Ended June 30, 2012)	$58.33	$35.68
First Quarter (Ended March 31, 2012)	$63.97	$46.55
Fiscal Year Ended December 31, 2011		
Fourth Quarter (Ended December 31, 2011)	$52.38	$28.87
Third Quarter (Ended September 30, 2011)	$63.31	$34.65
Second Quarter (Ended June 30, 2011)	$75.40	$52.08
First Quarter (Ended March 31, 2011)	$75.91	$55.26

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. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. All common share and per share amounts in this Annual Report on Form 10-K for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

On February 15, 2013, there were 622 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, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, our credit agreement restricts our ability to make any dividends or distributions on our common stock. Additionally, the indentures governing our senior subordinated notes contain restrictive covenants that may limit our ability to pay cash dividends on our common stock and our 6.25% convertible perpetual preferred 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, 2007 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, 2007 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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	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12
Whiting Petroleum Corporation	$ 100	$ 58	$ 124	$ 203	$ 162	$ 150
Standard & Poor’s Composite 500 Index	100	62	76	86	86	97
Dow Jones U.S. Oil Companies, Secondary Index	100	59	83	96	91	95

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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, 2012, 2011 and 2010 and the consolidated balance sheet information at December 31, 2012 and 2011 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, 2009 and 2008 and the consolidated balance sheet information at December 31, 2010, 2009 and 2008 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent acquisitions beginning on the following dates: proved properties in Colorado, September 1, 2010; additional interests in North Ward Estes, November 1, 2009 and October 1, 2009; and Flat Rock natural gas field, May 30, 2008.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(dollars in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil, NGL and natural gas sales	$2,137.7	$1,860.1	$1,475.3	$917.5	$1,316.5
Gain (loss) on hedging activities	2.3	8.8	23.2	38.8	(107.6)
Amortization of deferred gain on sale	29.5	13.9	15.6	16.6	12.1
Gain on sale of properties	3.4	16.3	1.4	5.9	—
Interest income and other	0.5	0.5	0.6	0.6	1.1
Total revenues and other income	2,173.4	1,899.6	1,516.1	979.4	1,222.1
Costs and expenses:					
Lease operating	376.4	305.5	268.3	237.3	241.2
Production taxes	171.6	139.2	103.9	64.7	87.5
Depreciation, depletion and amortization	684.7	468.2	393.9	394.8	277.5
Exploration and impairment	167.0	84.6	59.4	73.0	55.3
General and administrative	108.6	85.0	64.7	42.3	61.7
Interest expense	75.2	62.5	59.1	64.6	65.1
Loss on early extinguishment of debt	—	—	6.2	—	—
Change in Production Participation Plan liability	13.8	(0.9)	12.1	3.3	32.1
Commodity derivative (gain) loss, net	(85.9)	(24.8)	7.1	262.2	(7.1)
Total costs and expenses	1,511.4	1,119.3	974.7	1,142.2	813.3
Income (loss) before income taxes	662.0	780.3	541.4	(162.8)	408.8
Income tax expense (benefit)	247.9	288.7	204.8	(55.9)	156.7
Net income (loss)	414.1	491.6	336.7	(106.9)	252.1
Net loss attributable to noncontrolling interest	0.1	0.1	—	—	—
Net income (loss) available to shareholders	414.2	491.7	336.7	(106.9)	252.1
Preferred stock dividends(1)	(1.1)	(1.1)	(64.0)	(10.3)	—
Net income (loss) available to common shareholders	$413.1	$490.6	$272.7	$(117.2)	$252.1
Earnings (loss) per common share, basic(2)	$3.51	$4.18	$2.57	$(1.18)	$2.98
Earnings (loss) per common share, diluted(2)	$3.48	$4.14	$2.55	$(1.18)	$2.97

Other Financial Information:					
Net cash provided by operating activities	$1,401.2	$1,192.1	$997.3	$453.8	$766.5
Net cash used in investing activities	$(1,780.3)	$(1,760.0)	$(914.6)	$(523.5)	$(1,138.5)
Net cash provided by (used in) financing activities	$408.1	$564.8	$(75.7)	$72.1	$366.8
Capital expenditures	$2,171.5	$1,804.3	$923.8	$585.8	$1,330.9
Consolidated Balance Sheet Information:					
Total assets	$7,272.4	$6,045.6	$4,648.8	$4,029.5	$4,029.1
Long-term debt	$1,800.0	$1,380.0	$800.0	$779.6	$1,239.8
Total equity	$3,453.2	$3,029.1	$2,531.3	$2,270.1	$1,808.8

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(1) 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.

(2) 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 (loss) per common share, basic and diluted for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

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

Unless the context otherwise requires, the terms “Whiting,” “we,” “us,” “our” or “ours” when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation 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, Permian Basin, Mid-Continent, Michigan and Gulf Coast regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily 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. 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 believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. 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.

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 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.

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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. 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 2011:

	2011				2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude Oil	$94.25	$102.55	$89.81	$94.02	$102.94	$93.51	$92.19	$88.20
Natural Gas	$4.10	$4.32	$4.20	$3.54	$2.72	$2.21	$2.81	$3.41

Lower oil 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 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 and 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 is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant non-cash, mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

For a discussion of material changes to our proved, probable and possible reserves from December 31, 2011 to December 31, 2012 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.

2012 Highlights and Future Considerations

Operational Highlights.

Sanish. Our Sanish field in Mountrail County, North Dakota targets the Bakken and Three Forks formations. Net production in the Sanish field averaged 32.6 MBOE/d for the fourth quarter of 2012, representing a 4% increase from 31.4 MBOE/d in the third quarter of 2012. In 2012, net production in the Sanish field totaled 11.4 MMBOE (an average of 31.1 MBOE/d), representing a 40% increase from 8.1 MMBOE in 2011. As of December 31, 2012 we had seven drilling rigs active in the Sanish field. Two of these rigs are drilling multiple wells from the same drilling location or well pad (“pad drilling”). We plan to initiate a higher density pilot program in the Sanish field in the first half of 2013. We also plan to re-fracture stimulate several wells in our Sanish field in 2013.

Lewis & Clark/Pronghorn. Our Lewis & Clark/Pronghorn prospects are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). Net production in the Lewis & Clark/Pronghorn prospects averaged 13.4 MBOE/d in the fourth quarter of 2012, representing a 10% increase from 12.2 MBOE/d in the third quarter of 2012. As of December 31, 2012, we had seven drilling rigs operating in the Pronghorn prospect, making this our second most active area in the Williston Basin. Four of the rigs working in the Pronghorn prospect are utilizing pad drilling, drilling two or three wells from each pad. We are realizing cost efficiencies with the use of multi-well pads in the drilling and completion of wells. We also plan to conduct a higher density pilot program in the Pronghorn prospect in 2013.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 30 MMcf/d and which primarily processes production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d, and as of December 31, 2012 the plant was processing 18 MMcf/d. In November 2012, we began connecting other operators' wells to the plant. We intend to add inlet compression during 2013 in order to fully utilize the 30 MMcf/d processing capability. We are also currently installing fractionation equipment to convert NGLs into propane and butane, which end products are typically sold for higher realized prices in local markets. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and will continue to operate the Belfield plant and facilities. Additionally, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn prospect into the Bridger Four Bears oil transmission system. The use of this terminal will reduce our transportation costs per barrel and increase our returns on the development of this prospect.

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Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the fourth quarter of 2012, net production from the Hidden Bench/Tarpon prospects averaged 3.1 MBOE/d, representing a 23% increase from 2.5 MBOE/d in the third quarter of 2012. We drilled a highly productive Tarpon Federal well in late 2011 in the Tarpon prospect. Based on these results, we had planned to drill additional wells in Tarpon but were delayed by federal drilling permit requirements for these wells. During the fourth quarter of 2012, we received the required permits and drilled four additional wells in this area. We expect to drill most of the remaining planned Tarpon development wells during 2013. We have implemented pad drilling at our Tarpon prospect and plan to drill three wells from each pad.

Missouri Breaks Prospect. Our Missouri Breaks prospect, which is located in Richland County, Montana and McKenzie County, North Dakota, targets the Middle Bakken formation. In the fourth quarter of 2012, net production from the Missouri Breaks prospect averaged 1.7 MBOE/d, representing a 189% increase from 0.6 MBOE/d in the third quarter of 2012. We have drilled successful wells on the western and southern portions of our acreage. In the fourth quarter of 2012, we completed our first well on the eastern portion of our Missouri Breaks prospect.

Big Island Prospect. Our Big Island prospect, which is located in Golden Valley County, North Dakota and Wibaux County, Montana, targets the Red River formation. We are using 3-D seismic interpretations to identify Red River drilling locations at our Big Island prospect. We plan to use a horizontal well to test the Lower Red River "D" zone in 2013.

North Ward Estes. 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 substantial reserve additions and production increases, 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 in one of the largest phases of our eight-phase project at North Ward Estes, and we anticipate a production response in early 2013. Net production from North Ward Estes averaged 8.5 MBOE/d for the fourth quarter of 2012, which was consistent with production rates in the third quarter of 2012. As of December 31, 2012, we were injecting approximately 350 MMcf/d of CO2 into the field, over half of which is recycled.

Postle. The Postle field is located in Texas County, Oklahoma and produces from the Morrow sandstone. Postle averaged 7.8 MBOE/d in the fourth quarter of 2012, which represents a 4% decrease from 8.2 MBOE/d in the third quarter of 2012. As of December 31, 2012, we were injecting approximately 120 MMcf/d of CO2 into the field, over half of which is recycled.

Big Tex. Our Big Tex prospect in Pecos, Reeves and Ward counties, Texas targets the Brushy Canyon, Bone Spring and Wolfcamp horizons. During 2013, we plan to drill three wells in the Big Tex prospect, all of which are expected to be horizontal Wolfcamp wells. In late 2012, we completed a well utilizing a cemented liner and a plug and perf completion technique that is providing encouraging early results. We plan to implement this completion strategy on the horizontal wells drilled during 2013.

Redtail. Our Redtail prospect in the Denver Julesberg Basin in Weld County, Colorado targets the Niobrara formation. In 2012, we drilled 15 wells in this prospect, and we are very encouraged with the results. We plan to drill up to eight Niobrara "B" wells per spacing unit and utilize pad drilling to place the wells. The associated gas produced with the Niobrara oil must be processed before being sold, and we have therefore initiated the construction of our own gas processing plant in Weld County, Colorado for this purpose. The plant's planned inlet capacity will be 15 MMcf/d. The air permit for the plant was filed with the Colorado Department of Public Health and Environment in November 2012. We have ordered the major equipment necessary to construct this plant, and our plan is to have the plant online in early 2014. As of December 31, 2012, we had one drilling rig operating in this area, and we plan to add a second drilling rig in mid-year 2013 and a third upon completion of the plant.

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Financing Highlights. In October 2012, we entered into an amendment to our existing credit agreement that increased our borrowing base under the facility from $1.5 billion to $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase. All other terms of the credit agreement remain unchanged.

2013 Exploration and Development Budget. Our current 2013 exploration and development ("E&D") budget is $2,200.0 million, which we expect to fund substantially with net cash provided by our operating activities, borrowings under our credit facility and certain oil and gas property divestitures. This represents a 4% increase from the $2,111.5 million incurred on E&D (which consisted of exploration, development and acreage expenditures) during 2012, and based on this level of capital spending, we are forecasting production growth over our 2012 production level of 30.2 MMBOE. We expect to allocate $1,914.5 million of our 2013 budget to exploration and development activity, $108.0 million for land and $177.5 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 needed. Our 2013 E&D budget currently is allocated among our major development areas as indicated in the chart below. Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital expenditures.

Development Area	2013 Exploration and Development Budget (In millions)	
Northern Rockies	$	1,142.2
CO2 projects(1)		240.3
Central Rockies		135.6
Non-operated		164.0
Land		108.0
Exploration(2)		82.4
Facilities		177.5
Well work, miscellaneous costs, other		150.0
Total	$	2,200.0

(1) 2013 planned capital expenditures at our CO2 projects include $79.3 million for North Ward Estes CO2 purchases and $8.0 million for Postle CO2 purchases.

(2) Comprised primarily of exploration salaries, seismic activities, lease delay rentals and exploratory drilling.

Acquisition and Divestiture Highlights. On March 28, 2012, we completed an initial public offering of units of beneficial interest in Whiting USA Trust II ("Trust II"), selling 18,400,000 Trust II units at $20.00 per unit, which generated net proceeds of $322.3 million after underwriters' fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of $128.2 million.

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Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to Trust II in exchange for 100% of the trust's units issued, or 18,400,000 units. The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II's right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest. The conveyance of the net profits interest to Trust II consisted entirely of proved reserves of 10.61 MMBOE as of the January 1, 2012 effective date, representing 3% of our proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of our March 2012 average daily net production.

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

Results of Operations

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

	Year Ended December 31,		
	2012	2011	2010
Net production:			
Oil (MMBbl)	23.1	18.3	17.5
NGLs (MMBbl)	2.8	2.1	1.5
Natural gas (Bcf)	25.8	26.4	27.4
Total production (MMBOE)	30.2	24.8	23.6
Net sales (in millions):			
Oil(1)	$1,940.5	$1,621.5	$1,268.2
NGLs	108.9	108.6	74.0
Natural gas(1)	88.3	130.0	133.1
Total oil, NGL and natural gas sales	$2,137.7	$1,860.1	$1,475.3
Average sales prices:			
Oil (per Bbl)	$83.86	$88.61	$72.61
Effect of oil hedges on average price (per Bbl)	(1.25)	(1.67)	(1.47)
Oil net of hedging (per Bbl)	$82.61	$86.94	$71.14
Average NYMEX price (per Bbl)	$94.19	$95.14	$79.55
NGLs (per Bbl)	$39.36	$52.38	$47.33
Natural gas (per Mcf)	$3.42	$4.92	$4.86
Effect of natural gas hedges on average price (per Mcf)	0.06	0.04	0.04
Natural gas net of hedging (per Mcf)	$3.48	$4.96	$4.90
Average NYMEX price (per Mcf)	$2.79	$4.04	$4.39
Cost and expenses (per BOE):			
Lease operating expenses	$12.46	$12.33	$11.37
Production taxes	$5.68	$5.62	$4.40
Depreciation, depletion and amortization expense	$22.67	$18.89	$16.69
General and administrative expenses	$3.59	$3.43	$2.74

(1) Before consideration of hedging transactions.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $277.6 million to $2,137.7 million in 2012 compared to 2011. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 26%, and our NGL sales volumes increased 33% between periods, while our natural gas sales volumes decreased 2%. The oil volume increase resulted primarily from drilling success at our Sanish field, Lewis & Clark/Pronghorn prospects and our Hidden Bench/Tarpon prospects. During 2012, oil production from our Sanish field increased 2,475 MBbl, while oil production from our Lewis & Clark/Pronghorn prospects increased 2,150 MBbl compared to 2011, and oil production from our Hidden Bench/Tarpon prospects increased 495 MBbl over the same period in 2011. These production increases were partially offset by the Trust II divestiture, which decreased oil production by 915 MBOE in 2012. 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 relate to the same areas as our oil volume increases, such as our Sanish field, Lewis & Clark/Pronghorn prospects and our Hidden Bench/Tarpon prospects. The gas volume decline between periods was primarily the result of normal field production decline across several of our areas, as well as the Trust II divestiture. During 2012, gas production at our Flat Rock field decreased 1,795 MMcf, and gas production at our Canyon field decreased 645 MMcf compared to 2011. In addition, the Trust II divestiture in March 2012 negatively impacted gas production by 1,760 MMcf during 2012. These gas volume declines were partially offset by increases in associated gas production of 2,035 MMcf at our Lewis & Clark/Pronghorn prospects and 1,500 MMcf at our Sanish field, related to new wells drilled and completed in these areas during the past twelve months.

Partially offsetting the above crude oil and NGL production-related increases in net revenue, were decreases in the average sales prices realized for oil, NGLs and natural gas. Our average price for oil before the effects of hedging decreased 5% in 2012 as compared to 2011, while our average price for NGLs decreased 25%, and our average price for natural gas before the effects of hedging decreased 30% between periods.

Gain on Hedging Activities. Our gain on hedging activities decreased $6.4 million in 2012 as compared to 2011, and it consisted of the following (in thousands):

	Year Ended December 31,	
	2012	2011
Gains reclassified from AOCI on de-designated hedges	$2,338	$8,758

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from accumulated other comprehensive income (“AOCI”) into earnings unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains as gain on hedging activities.

See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of February 6, 2013.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2012 were $376.4 million, a $70.9 million increase over the same period in 2011. This rise in LOE in 2012 was primarily related to a $68.2 million increase in the cost of oil field goods and services and gas plant operating expenses, both of which were associated with net wells we added during the last twelve months. In addition, well workover activity increased to $81.9 million in 2012, as compared to $79.2 million in 2011, primarily due to a higher number of well workovers being conducted at our Sanish field and at our CO_2 project at our North Ward Estes field. This increase in workover expense was partially offset by decreases in the number of workovers being conducted in our Western Texas district and at our Postle CO_2 project.

Our lease operating expenses on a BOE basis only slightly increased during 2012. LOE per BOE amounted to $12.46 during 2012, which was up from $12.33 per BOE during 2011. This slight increase was mainly due to the higher costs of oil field goods and services, plant expenses and workover activity in 2012, as discussed above, which were largely offset by higher overall production volumes between periods.

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Production Taxes. Our production taxes during 2012 were $171.6 million, a $32.4 million increase over the same period in 2011, which increase was primarily due to higher oil, NGL and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil, NGL and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.0% and 7.5% for 2012 and 2011, respectively. Our production tax rate of 8.0% for 2012 was greater than the rate for 2011 due to successful wells completed during the past twelve months in North Dakota, which has an 11.5% tax rate. However, we attempt to take full advantage of production tax credits and exemptions allowed in our various jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $216.5 million in 2012 as compared to 2011. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2012	2011
Depletion	$673,789	$457,499
Depreciation	3,672	2,688
Accretion of asset retirement obligations	7,263	8,016
Total	$684,724	$468,203

DD&A increased in 2012 primarily due to $216.3 million in higher depletion expense between periods. This increase was the result of $121.1 million in higher depletion due to a rise in overall production volumes during 2012 and $95.2 million in higher depletion due to an increase in our depletion rate between periods. On a BOE basis, our DD&A rate of $22.67 for 2012 was 20% higher than the rate of $18.89 for 2011. The higher DD&A rate was mainly due to $2,031.6 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $82.3 million in 2012 as compared to 2011. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2012	2011
Exploration	$59,117	$45,861
Impairment	107,855	38,783
Total	$166,972	$84,644

Exploration costs increased $13.3 million during 2012 as compared to 2011 primarily due to higher exploratory dry hole costs. Exploratory dry hole costs for 2012 totaled $18.4 million, primarily related to five exploratory dry holes drilled in the Rocky Mountains, Permian Basin and Michigan regions during 2012. During 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling $4.9 million.

Impairment expense in 2012 and 2011 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $54.5 million in 2012 as compared to $34.9 million in 2011. Also included in impairment expense for 2012 is $46.9 million in non-cash impairment charges for the partial write-down of proved properties, mainly in the Rocky Mountains region, whose net book values exceeded their undiscounted future cash flows, whereas 2011 impairment expense only included $3.2 million of non-cash proved property impairment write-downs.

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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,	
	2012	2011
General and administrative expenses	$199,943	$153,341
Reimbursements and allocations	(91,370)	(68,356)
General and administrative expense, net	$108,573	$84,985

General and administrative expense before reimbursements and allocations increased $46.6 million during 2012 as compared to 2011 primarily due to higher employee compensation, an increase in accrued Production Participation Plan (the "Plan") distributions and a $7.8 million increase in professional fees and information technology costs. Employee compensation increased $21.7 million in 2012 as compared to 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. In addition, accrued distributions under the Plan increased general and administrative expenses by $10.7 million when comparing 2012 to 2011. Of this increase in general and administrative expenses related to Plan distributions, $8.6 million related to the Trust II net profits interest divestiture, and $2.1 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).

The increase in reimbursements and allocations for 2012 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained constant at 5% for 2012 and 2011.

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

	Year Ended December 31,	
	2012	2011
Senior Subordinated Notes	$40,250	$40,250
Credit agreement	28,043	17,049
Amortization of debt issue costs and debt discount	9,518	8,682
Other	148	109
Capitalized interest	(2,749)	(3,574)
Total	$75,210	$62,516

The increase in interest expense of $12.7 million between periods was mainly attributable to an $11.0 million increase in the amount of interest incurred on our credit agreement during 2012 as compared to 2011. Our credit agreement interest was higher in 2012 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during 2012 was $1,576.6 million versus $1,151.5 million for 2011. Our weighted average effective cash interest rate was 4.3% during 2012 compared to 5.0% during 2011.

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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, and only cash settlement gains and losses on commodity derivatives (except for settlements on embedded derivatives) are recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

	Year Ended December 31,	
	2012	2011
Change in unrealized (gains) losses on derivative contracts	$(113,395)	$(54,336)
Realized cash settlement losses	27,484	29,479
Total	$(85,911)	$(24,857)

With respect to our open derivative contracts at December 31, 2012, the futures curve of forecasted commodity prices ("forward price curve") for crude oil was generally below the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value asset position at the end of 2012. However, with respect to our open derivative contracts at December 31, 2011, the forward price curve for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of 2011. The change in unrealized (gains) losses on derivative contracts in 2012 resulted in a $113.4 million gain due to the significant downward shift in the forward price curve for NYMEX crude oil from January 1 to December 31, 2012 and the corresponding net fair value position shifting from a liability to an asset from January 1 to December 31, 2012. The change in unrealized (gains) losses on derivative contracts in 2011 resulted in a $54.3 million gain due to a less significant downward shift in the same forward price curve from January 1 to December 31, 2011.

Income Tax Expense. Income tax expense totaled $247.9 million for 2012 as compared to $288.7 million of income tax for 2011, a decrease of $40.8 million that was mainly related to $118.3 million in lower pre-tax income between periods.

Our effective tax rates for 2012 and 2011 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 only increased slightly between periods from 37.0% for 2011 to 37.4% for 2012.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $384.8 million to $1,860.1 million in 2011 compared to 2010. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 5%, and our NGL sales volumes increased 33% between periods, while our natural gas sales volumes decreased 3%. The oil volume increase resulted primarily from drilling success at our Lewis & Clark/Pronghorn prospects and our Hidden Bench/Tarpon prospects, as well as increased production attributable to our CO2 project at North Ward Estes. During 2011, oil production from our Lewis & Clark/Pronghorn prospects increased 1,045 MBbl compared to 2010, while oil production from our Hidden Bench/Tarpon prospects increased 240 MBbl, and oil production at our North Ward Estes field increased 300 MBbl over the same period in 2010. These production increases were partially offset by a decrease in oil production volumes of 400 MBbl at our Postle field primarily due to normal oil and gas production decline at this field. Our NGL production increased by 450 MBbl at our Sanish and Parshall fields in 2011 due to an increase in the number of wells connected to the Robinson Lake gas plant during the past twelve months. Gas production volumes decreased between periods primarily due to normal field production decline across many of our areas. Additionally, gas production at our Sanish and Parshall fields decreased 450 MMcf due to a large number of shut-in wells in this area during the second half of 2011. These gas volume decreases were largely offset by higher gas production of 1,755 MMcf at our Flat Rock field, related to new wells drilled and completed in this area during the past twelve months.

Also contributing to the above crude oil and NGL production-related increases in net revenue, were increases in the average sales prices realized for oil, NGLs and natural gas from 2010 to 2011. Our average price for oil before the effects of hedging increased 22% between periods, while our average price for NGLs increased 11%, and our average price for natural gas before the effects of hedging increased 1%.

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Gain on Hedging Activities. Our gain on hedging activities decreased $14.4 million in 2011 as compared to 2010, and it consisted of the following (in thousands):

	Year Ended December 31,	
	2011	2010
Gains reclassified from AOCI on de-designated hedges	$8,758	$23,198

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from AOCI into earnings unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains as gain on hedging activities.

See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of February 6, 2013.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2011 were $305.5 million, a $37.1 million increase over the same period in 2010. This rise in LOE in 2011 was related to a higher level of workover activity, as well as a $24.5 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months. Workovers activity increased to $79.2 million in 2011, as compared to $66.6 million in 2010, primarily due to a higher number of well workovers being conducted on our two main CO2 projects.

Our lease operating expenses on a BOE basis also increased in 2011. LOE per BOE amounted to $12.33 during 2011, which was up from $11.37 per BOE during 2010. This increase was mainly due to the higher amount of workover activity in 2011, as discussed above.

Production Taxes. Our production taxes during 2011 were $139.2 million, a $35.3 million increase over the same period in 2010, which increase was primarily due to higher oil, NGL and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil, NGL and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 7.5% and 7.0% for 2011 and 2010, respectively. However, we attempt to take full advantage of production tax credits and exemptions allowed in our various jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $74.3 million in 2011 as compared to 2010. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Depletion	$457,499	$384,383
Depreciation	2,688	2,291
Accretion of asset retirement obligations	8,016	7,223
Total	$468,203	$393,897

DD&A increased in 2011 primarily due to $73.1 million in higher depletion expense between periods. This increase was the result of $51.2 million in higher depletion due to an increase in our depletion rate between periods and $21.9 million in higher depletion due to a rise in overall production volumes during 2011. On a BOE basis, our DD&A rate of $18.89 for 2011 was 13% higher than the rate of $16.69 for 2010. The higher DD&A rate was mainly due to

$1,549.3 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

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Exploration and Impairment Costs. Our exploration and impairment costs increased $25.3 million in 2011 as compared to 2010. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Exploration	$45,861	$32,846
Impairment	38,783	26,525
Total	$84,644	$59,371

Exploration costs increased $13.0 million during 2011 as compared to 2010 primarily due to an increase in geology-related general and administrative expenses, an increase in geological and geophysical ("G&G") activity and higher exploratory dry hole costs. Geology-related general and administrative expenses increased $5.9 million between periods. G&G costs, such as seismic studies, amounted to $19.0 million during 2011 as compared to $14.3 million during 2010. During 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling $4.9 million, while we drilled three exploratory dry holes in the Gulf Coast region totaling $3.8 million during 2010.

Impairment expense in 2011 and 2010 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. A higher amount of undeveloped leasehold costs were amortized to impairment on a group basis for 2011 as compared to 2010. Also included in impairment expense for 2011 is $3.2 million in non-cash impairment charges for the partial write-down of mainly natural gas proved properties whose net book values exceeded their undiscounted future cash flows, whereas 2010 impairment expense included a $5.8 million impairment write-down of the remaining undeveloped leasehold costs related to the central Utah Hingeline play.

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,	
	2011	2010
General and administrative expenses	$153,341	$118,606
Reimbursements and allocations	(68,356)	(53,912)
General and administrative expense, net	$84,985	$64,694

General and administrative expense before reimbursements and allocations increased $34.7 million during 2011 as compared to 2010 primarily due to higher employee compensation and an increase in accrued Plan distributions. Employee compensation increased $25.2 million in 2011 as compared to 2010 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. In addition, accrued distributions under the Plan increased general and administrative expenses by $6.9 million when comparing 2011 to 2010.

The increase in reimbursements and allocations in 2011 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales increased from 4% for 2010 to 5% for 2011.

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

	Year Ended December 31,	
	2011	2010
Senior Subordinated Notes	$40,250	$42,034
Credit agreement	17,049	9,225
Amortization of debt issue costs and debt discount	8,682	10,592
Other	109	147
Capitalized interest	(3,574)	(2,920)
Total	$62,516	$59,078

The increase in interest expense of $3.4 million between periods was mainly attributable to a $7.8 million increase in the amount of interest incurred on our credit agreement during 2011 as compared to 2010. Our credit agreement interest was higher in 2011 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during 2011 was $1,151.5 million versus $739.9 million for 2010. However, our weighted average effective cash interest rate was lower during 2011 at 5.0% compared to 6.9% during 2010. The increase in interest incurred on our credit agreement was partially offset by lower amortization of debt issuance costs and debt discounts of $1.9 million and lower interest of $1.8 million on our Senior Subordinated Notes. These decreases resulted from redeeming $150.0 million of 7.25% notes and $220.0 million of 7.25% notes in early September 2010. Also in September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018.

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, and only cash settlement gains and losses on commodity derivatives (except for settlements on embedded derivatives) are recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Change in unrealized (gains) losses on derivative contracts	$(54,336)	$(17,537)
Realized cash settlement losses	29,479	24,599
Total	$(24,857)	$7,062

With respect to our open derivative contracts at December 31, 2011 and 2010, the forward price curve for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in 2011 resulted in a $54.3 million gain in such net liability position due to the significant downward shift in the forward price curve for NYMEX crude oil from January 1 to December 31, 2011. The change in unrealized (gains) losses on derivative contracts in 2010 resulted in a $17.5 million gain due to a less significant downward shift in the same forward price curve from January 1 to December 31, 2010.

Income Tax Expense. Income tax expense totaled $288.7 million for 2011 as compared to $204.8 million of income tax for 2010, an increase of $83.9 million that was mainly related to $238.9 million of higher pre-tax income between periods.

Our effective tax rates for 2011 and 2010 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 income tax rate decreased from 37.8% for 2010 to 37.0% for 2011. This change in our effective income tax rate between periods was primarily attributable to recent North Dakota corporate tax legislation, which created a one-time benefit in 2011.

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Liquidity and Capital Resources

Overview. At December 31, 2012, our debt to total capitalization ratio was 34.3%, we had $44.8 million of cash on hand and $3,445.0 million of equity. At December 31, 2011, our debt to total capitalization ratio was 31.4%, we had $15.8 million of cash on hand and $3,020.9 million of equity. During 2012, we generated $1,401.2 million of cash provided by operating activities, an increase of $209.1 million from 2011. Cash provided by operating activities increased primarily due to higher crude oil and NGL production volumes in 2012. This positive factor was partially offset by lower realized sales prices for oil, NGLs and natural gas and lower natural gas production volumes in 2012, as well as increased lease operating expenses, production taxes, general and administrative and cash interest expense during 2012 as compared to 2011. 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 2012. Cash flows from operating activities plus $420.0 million in net borrowings under our credit agreement, $322.3 million of proceeds from the sale of Trust II units and $69.2 million of proceeds from the sale of oil and gas properties were used to finance $2,050.0 million of drilling and development expenditures and $121.4 million of cash acquisition capital expenditures paid in 2012. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during 2012 (in thousands):

	Drilling and Development Expenditures(1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains(2)	$ 1,471,278	$ 80,272	$ 30,384	$ 1,581,934	75%
Permian Basin	375,816	14,585	19,753	410,154	19%
Mid-Continent	78,197	430	1,057	79,684	4%
Gulf Coast	10,039	23,884	2,601	36,524	2%
Michigan	(2,103)	4	5,322	3,223	-%
Total incurred	1,933,227	119,175	59,117	2,111,519	100%
Decrease in accrued capital expenditures	32,164	-	-	32,164	
Total paid	$ 1,965,391	$ 119,175	$ 59,117	$ 2,143,683	

(1) For purposes of this schedule, exploratory dry hole costs of $18.4 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

(2) Proceeds from the sale of the Belfield gas plant of $66.2 million have been included above as a reduction to drilling and development expenditures in the Rocky Mountains region.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2013 E&D budget is $2,200.0 million, which we expect to fund substantially with net cash provided by our operating activities, borrowings under our credit facility and certain oil and gas property divestitures. This represents a 4% increase from the $2,111.5 million incurred on exploration, development and acreage expenditures during 2012, and based on this level of capital spending, we are forecasting production growth in 2013 over our 2012 production level of 30.2 MMBOE. We expect to allocate $1,914.5 million of our 2013 budget to exploration and development activity, $108.0 million for undeveloped acreage and $177.5 million for facilities. Although we have only budgeted $108.0 million for undeveloped leaseholds in 2013, 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 $2,200.0 million, 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. In addition, 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 Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2012 had a borrowing base of $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase. As of December 31, 2012, we had $797.6 million of available borrowing capacity, which was net of $1,200.0 million in borrowings and $2.4 million in letters of credit outstanding.

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 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, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 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, 2012, $47.6 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is due. Interest 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 0.50% or an adjusted LIBOR rate plus 1.00%, 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 lesser of the aggregate commitments of the lenders or the borrowing base.

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

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for the quarters ending March 31, 2013 and thereafter 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, 2012.

For further information on the interest rates and loan security related to our credit agreement, refer to the Long-Term Debt footnote in the Notes to Consolidated Financial Statements.

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Senior Subordinated Notes. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014.

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, 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, 2012. 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.

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.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of $143.8 million (which amount comprises both the long and short-term portions of this obligation) as of December 31, 2012, since we cannot determine with accuracy the timing or amounts of future payments other than the short-term portion. The following table summarizes our obligations and commitments as of December 31, 2012 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (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 (a)	$1,800,000	$-	$250,000	$1,200,000	$350,000
Cash interest expense on debt (b)	227,143	63,770	93,998	52,312	17,063
Derivative contract liability fair value (c)	23,633	21,955	1,678	-	-
Asset retirement obligations (d)	97,818	11,639	12,508	12,679	60,992
Tax sharing liability (e)	22,526	1,452	21,074	-	-
Purchase obligations (f)	712,296	60,899	204,822	183,787	262,788
Drilling rig contracts (g)	187,342	92,823	93,601	918	-
Operating leases (h)	33,947	5,402	12,058	10,566	5,921
Total	$3,104,705	$257,940	$689,739	$1,460,262	$696,764

(a) Long-term debt consists of the 7% Senior Subordinated Notes due 2014, the 6.5% Senior Subordinated Notes due 2018 and the outstanding borrowings under our credit agreement due in 2016, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7% Senior Subordinated Notes due 2014 and the 6.5% Senior Subordinated Notes due 2018 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 2016 instrument due date and is estimated at a fixed interest rate of 2.0%.

(c) The above derivative obligation at December 31, 2012 primarily consists of (i) a $21.0 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations and (ii) a $2.6 million payable to Trust II for derivative contracts that we have entered into but have in turn conveyed to Trust II (although these derivatives are in a fair value asset position at quarter end, 90% of such derivative assets are due to Trust II under the terms of the conveyance). With respect to only a portion of our open derivative contracts at December 31, 2012 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility.

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(d) 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 facilities.

(e) Amounts shown represent the present value of estimated payments due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

(f) We have four take-or-pay purchase agreements, two agreements expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby we have committed to buy certain volumes of CO2 for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with three different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, we have two ship-or-pay agreements with two different parties, one expiring in June 2013 and one expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via certain pipelines or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

(g) We currently have 12 drilling rigs under long-term contract, of which three drilling rigs expire in 2013, six in 2014, one in 2015 and two in 2016. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2012, early termination of the remaining contracts would require termination penalties of $145.1 million, which would be in lieu of paying the remaining drilling commitments of $187.3 million. 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.

(h) We lease 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 46,300 square feet of office space in Midland, Texas expiring in 2020 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, North Dakota under an operating lease agreement expiring in 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, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and 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 Adopted and Recently Issued Accounting Pronouncements footnote in the Notes to Consolidated Financial Statements.

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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, asset retirement obligations, and our long-term Production Participation Plan liability. 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 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, 2012. 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, impairment calculations (when impairment indicators arise) and our Production Participation Plan liability 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 the 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 exploitation and development program, as well as future economic conditions.

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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 future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds 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.

Asset Retirement Obligation. Our asset retirement obligations (“AROs”) consist primarily 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 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. We have a Production Participation Plan (“Plan”) in which all employees participate. Each year, a deemed economic interest in all oil and gas properties acquired or developed during the year is contributed to the Plan. The Compensation Committee of the Board of Directors, in its discretion for each Plan year, allocates a percentage of future net income (defined as gross revenues less production taxes, royalties and direct lease operating expenses) attributable to such properties to Plan participants. Once contributed and allocated, the interests (not legally conveyed) are fixed for each Plan year. The short-term obligation related to the Production Participation Plan is included in the accrued liabilities and other line item in our consolidated balance sheets. This obligation is based on cash flows during the year and is paid annually in cash after year end. The calculation of this liability depends in part on our estimates of accrued revenues and costs as of the end of each reporting period as discussed below under “Revenue Recognition.” The vested long-term obligation related to the Production Participation Plan is the “Production Participation Plan liability” line item in the consolidated balance sheets. This liability is derived primarily from reserve report estimates, which as discussed above, are subject to revision as more information becomes available. Variances between estimates used to calculate liabilities related to the Production Participation Plan and actual sales, costs and production data are integrated into the liability calculations in the period identified. A 10% increase to the pricing assumptions used in the measurement of this liability at December 31, 2012 would have decreased net income before taxes by $16.3 million in 2012.

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, they may also limit future revenues from favorable price movements. We primarily utilize costless collars, which are generally placed with major financial institutions.

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All derivative instruments are recorded on the consolidated balance sheet at fair value, other than the derivative instruments that meet the "normal purchase normal sales" 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 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 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. 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 related 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 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. Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method, which is the only method permitted under FASB ASC Topic 805, Business Combinations, and involves the use of significant judgment.

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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 of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, 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 value 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. 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. Consequently, there was no goodwill nor any bargain purchase gains recognized on any of our business combinations.

Effects of Inflation and Pricing

We experienced increased costs during 2011 and 2012 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 put 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 the 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 the Private Securities Litigation Reform Act of 1995. 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 "sho 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.

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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; 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 CO2 necessary to carry out our enhanced oil recovery projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; 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; impacts of the global recession and tight credit markets; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions and the risks related thereto; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; 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 in the regions in which we operate; risks arising out of our hedging transactions; 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. The prices we receive for our production depend on numerous factors beyond our control. Based on 2012 production, our income before income taxes for 2012 would have moved up or down $194.0 million for each 10% change in oil prices per Bbl, $10.9 million for each 10% change in NGL prices per Bbl and $8.8 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate 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. Recognition of derivative cash settlement gains and losses in the consolidated statements of income occurs in the period that hedged production volumes are sold, and the related hedge contract expires.

Commodity Derivative Contracts—Our outstanding hedges as of February 6, 2013 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Collars	Crude Oil	01/2013 to 03/2013	290,000	$47.67/$90.21
	Crude Oil	04/2013 to 06/2013	290,000	$47.67/$90.21
	Crude Oil	07/2013 to 09/2013	290,000	$47.67/$90.21
	Crude Oil	10/2013	290,000	$47.67/$90.21
	Crude Oil	11/2013	190,000	$47.22/$85.06
Three-way collars(1)	Crude Oil	01/2013 to 03/2013	910,000	$70.00/$85.00/$114.80
	Crude Oil	04/2013 to 06/2013	1,040,000	$71.25/$85.63/$113.95
	Crude Oil	07/2013 to 09/2013	1,040,000	$71.25/$85.63/$113.95
	Crude Oil	10/2013 to 12/2013	1,040,000	$71.25/$85.63/$113.95

(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-price Natural Gas Contracts. We have various fixed-price gas sales contracts with end users for a portion of the natural gas we produce in Colorado and Utah. Our future production volumes projected to be sold under these fixed-price contracts as of February 6, 2013 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	01/2013 to 03/2013	360,000	$5.47

Natural Gas	04/2013 to 06/2013	364,000	$5.47
Natural Gas	07/2013 to 09/2013	368,000	$5.47
Natural Gas	10/2013 to 12/2013	368,000	$5.47
Natural Gas	01/2014 to 03/2014	330,000	$5.49
Natural Gas	04/2014 to 06/2014	333,667	$5.49
Natural Gas	07/2014 to 09/2014	337,333	$5.49
Natural Gas	10/2014 to 12/2014	337,333	$5.49

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Commodity Derivatives Conveyed to Whiting USA Trust II. In connection with our conveyance on March 28, 2012 of a term net profits interest to Whiting USA Trust II ("Trust II"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,030 MBbl of crude oil from 2013 through 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

The table below summarizes all of the outstanding costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Trust II (of which we retain 10% of the future economic results and third-party public holders of Trust II units receive 90% of the future economic results):

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling
Collars	Crude Oil	01/2013 to 03/2013	45,600	$80.00/$122.50
	Crude Oil	04/2013 to 06/2013	45,500	$80.00/$122.50
	Crude Oil	07/2013 to 09/2013	44,500	$80.00/$122.50
	Crude Oil	10/2013 to 12/2013	43,400	$80.00/$122.50
	Crude Oil	01/2014 to 03/2014	42,500	$80.00/$122.50
	Crude Oil	04/2014 to 06/2014	41,500	$80.00/$122.50
	Crude Oil	07/2014 to 09/2014	40,600	$80.00/$122.50
	Crude Oil	10/2014 to 12/2014	39,700	$80.00/$122.50

The collared hedges shown above (excluding the fixed-price natural gas contracts) have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil hedges outstanding as of December 31, 2012, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2012 would cause a decrease or increase, respectively, of $51.0 million in our commodity derivative gain.

Embedded Commodity Derivative Contracts—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. We have entered into certain contracts for oil field goods and services with price adjustment clauses that are linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for these goods and services in a climate of declining oil prices. We have determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and we have therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements. These embedded commodity derivative contracts have not been designated as hedges, and therefore all changes in fair value since inception have been recorded immediately to earnings.

Drilling Rig Contracts. As of December 31, 2012, we had two contracts with drilling rig companies, whereby the rig day rates increased or decreased along with changes in the price of NYMEX crude oil. These drilling rig contracts have termination dates of April 2014 and September 2014. For these embedded commodity derivative contracts, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2012 would cause a decrease or increase, respectively, of $0.9 million in our commodity derivative (gain) loss.

CO2 Purchase Contract. In May 2011, we entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in our EOR project at our North Ward Estes field in Texas. The price per Mcf of CO2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2012 would cause a decrease or increase, respectively, of $14.4 million in our commodity derivative (gain) loss.

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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. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Subordinated Notes. At December 31, 2012, our outstanding principal balance under our credit agreement was $1,200.0 million, and the weighted average interest rate on the outstanding principal balance was 2.0%. At December 31, 2012, the carrying amount approximated fair market value. Assuming a constant debt level of $1,200.0 million, 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 $11.1 million over a 12-month time period.

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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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2013

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WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 44,800	$ 15,811
Accounts receivable trade, net	318,265	262,515
Prepaid expenses and other	21,347	20,377
Total current assets	384,412	298,703
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	8,849,515	7,221,550
Unproved properties	362,483	354,774
Other property and equipment	141,738	150,933
Total property and equipment	9,353,736	7,727,257
Less accumulated depreciation, depletion and amortization	(2,590,203)	(2,088,517)
Total property and equipment, net	6,763,533	5,638,740
Debt issuance costs	28,748	33,306
Other long-term assets	95,726	74,860
TOTAL ASSETS	$ 7,272,419	$ 6,045,609
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 131,370	$ 56,673
Accrued capital expenditures	110,663	142,827
Accrued liabilities and other	180,622	157,214
Revenues and royalties payable	149,692	103,894
Taxes payable	33,283	31,195
Derivative liabilities	21,955	73,647
Deferred income taxes	9,394	1,584
Total current liabilities	636,979	567,034
Long-term debt	1,800,000	1,380,000
Deferred income taxes	1,063,681	823,643
Derivative liabilities	1,678	47,763
Production Participation Plan liability	94,483	80,659
Asset retirement obligations	86,179	61,984
Deferred gain on sale	110,395	29,619
Other long-term liabilities	25,852	25,776
Total liabilities	3,819,247	3,016,478
Commitments and contingencies		
Equity:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,391 shares issued and outstanding as of December 31, 2012 and 2011,	-	-

aggregate liquidation preference of $17,239,100 at December 31, 2012				
Common stock, $0.001 par value, 300,000,000 shares authorized; 118,582,477 issued and 117,631,451 outstanding as of December 31, 2012, 118,105,279 issued and 117,380,884 outstanding as of December 31, 2011		119		118
Additional paid-in capital		1,566,717		1,554,223
Accumulated other comprehensive income (loss)		(1,236)		240
Retained earnings		1,879,388		1,466,276
Total Whiting shareholders' equity		3,444,988		3,020,857
Noncontrolling interest		8,184		8,274
Total equity		3,453,172		3,029,131
TOTAL LIABILITIES AND EQUITY	$	7,272,419	$	6,045,609

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, 2012	2011	2010
REVENUES AND OTHER INCOME:			
Oil, NGL and natural gas sales	$ 2,137,714	$ 1,860,146	$ 1,475,288
Gain on hedging activities	2,338	8,758	23,198
Amortization of deferred gain on sale	29,458	13,937	15,613
Gain on sale of properties	3,423	16,313	1,388
Interest income and other	519	468	612
Total revenues and other income	2,173,452	1,899,622	1,516,099
COSTS AND EXPENSES:			
Lease operating	376,424	305,487	268,348
Production taxes	171,625	139,190	103,880
Depreciation, depletion and amortization	684,724	468,203	393,897
Exploration and impairment	166,972	84,644	59,371
General and administrative	108,573	84,985	64,694
Interest expense	75,210	62,516	59,078
Loss on early extinguishment of debt	-	-	6,235
Change in Production Participation Plan liability	13,824	(865)	12,091
Commodity derivative (gain) loss, net	(85,911)	(24,857)	7,062
Total costs and expenses	1,511,441	1,119,303	974,656
INCOME BEFORE INCOME TAXES	662,011	780,319	541,443
INCOME TAX EXPENSE (BENEFIT):			
Current	(669)	3,853	4,979
Deferred	248,581	284,838	199,811
Total income tax expense	247,912	288,691	204,790
NET INCOME	414,099	491,628	336,653
Net loss attributable to noncontrolling interest	90	59	-
NET INCOME AVAILABLE TO SHAREHOLDERS	414,189	491,687	336,653
Preferred stock dividends and inducement premium	(1,077)	(1,077)	(63,970)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 413,112	$ 490,610	$ 272,683
EARNINGS PER COMMON SHARE (1):			
Basic	$ 3.51	$ 4.18	$ 2.57
Diluted	$ 3.48	$ 4.14	$ 2.55

WEIGHTED AVERAGE SHARES OUTSTANDING (1):			
Basic	117,601	117,345	106,338
Diluted	119,028	118,668	107,846

(1) All share and per share amounts have been retroactively restated for the 2010 period to reflect the Company’s two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31, 2012	2011	2010
NET INCOME	$ 414,099	$ 491,628	$ 336,653
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
OCI amortization on de-designated hedges(1)	(1,476)	(5,528)	(14,645)
Total other comprehensive loss, net of tax	(1,476)	(5,528)	(14,645)
COMPREHENSIVE INCOME	412,623	486,100	322,008
Comprehensive loss attributable to noncontrolling interest	90	59	-
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 412,713	$ 486,159	$ 322,008

(1) Presented net of income tax expense of $862, $3,230 and $8,553 for the years ended December 31, 2012, 2011 and 2010, respectively.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 414,099	$ 491,628	$ 336,653
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	684,724	468,203	393,897
Deferred income tax expense	248,581	284,838	199,811
Amortization of debt issuance costs and debt discount	9,518	8,682	10,592
Stock-based compensation	18,190	13,509	8,871
Amortization of deferred gain on sale	(29,458)	(13,937)	(15,613)
Gain on sale of properties	(3,423)	(16,313)	(1,388)
Undeveloped leasehold and oil and gas property impairments	107,855	38,783	26,525
Exploratory dry hole costs	18,428	4,924	3,819
Loss on early extinguishment of debt	-	-	6,235
Change in Production Participation Plan liability	13,824	(865)	12,091
Unrealized gain on derivative contracts	(115,733)	(63,093)	(40,736)
Other, net	(18,708)	(13,512)	(4,013)
Changes in current assets and liabilities:			
Accounts receivable trade	(55,750)	(62,802)	(47,631)
Prepaid expenses and other	2,535	(3,771)	(3,387)
Accounts payable trade and accrued liabilities	58,647	33,135	66,663
Revenues and royalties payable	45,798	21,770	35,797
Taxes payable	2,088	904	9,103
Net cash provided by operating activities	1,401,215	1,192,083	997,289
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(121,430)	(250,041)	(184,729)
Drilling and development capital expenditures	(2,050,029)	(1,554,271)	(739,047)
Proceeds from sale of oil and gas properties	69,190	69,276	9,202
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	322,257	-	-
Issuance of note receivable	(306)	(25,000)	-
Net cash used in investing activities	(1,780,318)	(1,760,036)	(914,574)
CASH FLOWS FROM FINANCING ACTIVITIES:			
	-	-	350,000

Issuance of 6.5% Senior Subordinated Notes due 2018			
Redemption of 7.25% Senior Subordinated Notes due 2012	-	-	(150,000)
Redemption of 7.25% Senior Subordinated Notes due 2013	-	-	(223,988)
Premium on induced conversion of 6.25% convertible perpetual preferred stock	-	-	(47,529)
Contributions from noncontrolling interest	-	2,500	-
Preferred stock dividends paid	(1,077)	(1,077)	(16,441)
Long-term borrowings under credit agreement	2,340,000	1,760,000	1,150,000
Repayments of long-term borrowings under credit agreement	(1,920,000)	(1,180,000)	(1,110,000)
Repayments to Alliant Energy Corporation	(2,329)	(1,871)	(1,615)
Debt issuance costs	(2,807)	(5,691)	(20,471)
Restricted stock used for tax withholdings	(5,695)	(9,049)	(5,679)
Net cash provided by (used in) financing activities	408,092	564,812	(75,723)

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, 2012	2011	2010
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ 28,989	$ (3,141)	$ 6,992
CASH AND CASH EQUIVALENTS:			
Beginning of period	15,811	18,952	11,960
End of period	$ 44,800	$ 15,811	$ 18,952
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Income taxes paid (refunded), net	$ (268)	$ 4,065	$ 6,181
Interest paid, net of amounts capitalized	$ 68,005	$ 53,761	$ 46,332
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 110,663	$ 142,827	$ 84,789
NONCASH FINANCING ACTIVITIES:			
Contributions from noncontrolling interest	$ -	$ 5,833	$ -
Issuance of common stock related to the induced conversion of preferred stock	$ -	$ -	$ 317,406
Preferred stock cancelled in connection with its induced conversion	$ -	$ -	$ (317,406)

See notes to consolidated financial statements.

(Concluded)

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands)

	Preferred Stock		Common Stock (1)		Additional Paid-in	Accumulated Other Comprehensive Income	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital	(Loss)	Earnings	Equity	Interest	Equity
BALANCES-January 1, 2010	3,450	$3	102,728	$51	$1,546,635	$20,413	$702,983	$2,270,085	$-	$2,270,085
Net income	-	-	-	-	-	-	336,653	336,653	-	336,653
Other comprehensive income	-	-	-	-	-	(14,645)	-	(14,645)	-	(14,645)
Induced conversion of convertible perpetual preferred stock	(3,277)	(3)	15,098	8	(5)	-	(47,529)	(47,529)	-	(47,529)
Restricted stock issued	-	-	325	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(27)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(156)	-	(5,679)	-	-	(5,679)	-	(5,679)
Stock-based compensation	-	-	-	-	8,871	-	-	8,871	-	8,871
Preferred dividends paid	-	-	-	-	-	-	(16,441)	(16,441)	-	(16,441)
BALANCES-December 31, 2010	173	-	117,968	59	1,549,822	5,768	975,666	2,531,315	-	2,531,315
Net income	-	-	-	-	-		491,687	491,687	(59)	491,628
Other comprehensive income	-	-	-	-	-	(5,528)	-	(5,528)	-	(5,528)
Conversion of preferred stock to common	(1)	-	1	-	-	-	-	-	-	-–
Two-for-one stock split	-	-	-	59	(59)	-	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	8,333	8,333
Restricted stock issued	-	-	304	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(20)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(148)	-	(9,049)	-	-	(9,049)	-	(9,049)
Stock-based compensation	-	-	-	-	13,509	-	-	13,509	-	13,509
Preferred dividends paid	-	-	-	-	-	-	(1,077)	(1,077)	-	(1,077)
BALANCES-December 31, 2011	172	-	118,105	118	1,554,223	240	1,466,276	3,020,857	8,274	3,029,131
Net income	-	-	-	-	-	-	414,189	414,189	(90)	414,099
	-	-	-	-	-	(1,476)	-	(1,476)	-	(1,476)

Other comprehensive income										
Restricted stock issued	-	-	592	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(9)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(106)	-	(5,695)	-	-	(5,695)	-	(5,695)
Stock-based compensation	-	-	-	-	18,190	-	-	18,190	-	18,190
Preferred dividends paid	-	-	-	-	-	-	(1,077)	(1,077)	-	(1,077)
BALANCES-December 31, 2012	172	$-	118,582	$119	$1,566,717	$(1,236)	$1,879,388	$3,444,988	$8,184	$3,453,172

(1) All common share amounts (except par values) have been retroactively restated for the 2010 period to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that explores for, develops, acquires and produces crude oil, NGLs and natural gas primarily in the Rocky Mountains, Permian Basin, Mid-Continent, Michigan and Gulf Coast regions of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements include the accounts of Whiting Petroleum Corporation, its consolidated subsidiaries and Whiting's pro rata share of the accounts of Whiting USA Trust I ("Trust I") pursuant to Whiting's 15.8% ownership interest in Trust I. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) Production Participation Plan and other accrued liabilities; (8) valuation of derivative instruments; and (9) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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

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

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. At December 31, 2012 and 2011, the Company had an allowance for doubtful accounts of $3.9 million and $1.7 million, respectively.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or market value and is included in prepaid expenses and other.

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Oil and Gas Properties

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

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

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

Interest cost is capitalized as a component of property cost for development projects that require greater than six months to be readied for their intended use. During 2012, 2011 and 2010, the Company capitalized interest of $2.7