Oasis Petroleum Inc.
Form 10-K
February 26, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2014

OR

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

Commission file number: 1-34776

Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

Delaware	80-0554627
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 1500 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)
(281) 404-9500	
(Registrant's telephone number, including area code)	
Securities Registered Pursuant to Section 12(b) of the Act:	
Common Stock, par value $0.01 per share	New York Stock Exchange
(Title of Class)	(Name of Exchange)
Securities Registered Pursuant to Section 12(g) of the Act: None	

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

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

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 ý 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 ý 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. ý

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.

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $5,653,377,903

Number of shares of registrant's common stock outstanding as of February 20, 2015: 102,451,226

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Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2015 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference into Part III of this report for the year ended December 31, 2014.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended ("Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- timing and amount of future production of oil and natural gas;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- costs of exploiting and developing our properties and conducting other operations;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating well services and midstream companies;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions;
- integration and benefits of property acquisitions or the effects of such acquisitions on our cash position and levels of indebtedness;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- our financial strategy, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- oil and natural gas realized prices;
- general economic conditions;
- operating environment, including inclement weather conditions;
- effectiveness of risk management activities;
- competition in the oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- technology;
- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and

elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

Item 1. Business

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the "Company," "we," "us," or "our") is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the North Dakota and Montana regions of the Williston Basin. As of December 31, 2014, we have accumulated 505,503 net leasehold acres in the Williston Basin, of which approximately 86% is held-by-production. We are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. Our management team has a proven track record in identifying, acquiring and executing large, repeatable development drilling programs, which we refer to as "resource conversion" opportunities, and has substantial Williston Basin experience. In 2014, we completed and placed on production 195 gross operated wells in the Williston Basin. We have built our Williston Basin assets primarily through acquisitions and development in our two primary project areas: West Williston and East Nesson. In March 2014, we completed the sale of certain non-operated properties in our Sanish project area (the "Sanish Divestiture"). Please see Note 7 to our audited consolidated financial statements for a description of the Sanish Divestiture.

DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 272.1 MMBoe as of December 31, 2014, of which 54% were classified as proved developed and of which 87% were oil. The following table presents summary data for each of our primary project areas as of December 31, 2014:

		Productive Bakken and Three Forks Wells		Estimated net proved reserves as of December 31, 2014		2014 Average daily production
Project area	Net acreage	Gross	Net	MMBoe	% Developed	Boe/d
West Williston	357,584	629	342.7	197.8	52 %	30,627
East Nesson	147,919	344	185.1	74.3	60 %	14,641
Sanish[(1)]	—	—	—	—	—	388
Total	505,503	973	527.8	272.1	54 %	45,656

(1) Represents data related to non-operated properties in our Sanish project area, which were sold in the Sanish Divestiture in March 2014.

Our history

Oasis Petroleum Inc. was incorporated in February 2010 pursuant to the laws of the State of Delaware to become a holding company for Oasis Petroleum LLC ("OP LLC"), our predecessor, which was formed as a Delaware limited liability company in February 2007. We completed our initial public offering ("IPO") in June 2010. In connection with our IPO and related corporate reorganization, we acquired all of the outstanding membership interests in OP LLC in exchange for shares of our common stock. Oasis Petroleum North America LLC ("OPNA") conducts our exploration and production activities and owns our proved and unproved oil and natural gas properties. In 2011, we formed Oasis Well Services LLC ("OWS"), which provides well services to OPNA, and Oasis Petroleum Marketing LLC ("OPM"), which provides marketing services to OPNA. In 2013, we formed Oasis Midstream Services LLC ("OMS"), which provides midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.

Our business strategy

Our goal is to enhance value by investing capital to build reserves, production and cash flows at attractive rates of return through the following strategies:

- Efficiently develop our Williston Basin leasehold position. We intend to develop our acreage position to maximize the value of our resource potential, while maintaining flexibility to preserve future value when oil prices are low. During 2014, when the NYMEX West Texas Intermediate ("WTI") crude oil index price averaged $92.07 per barrel throughout

the year, we completed and brought on production 195 gross (147.4 net) operated Bakken and Three Forks wells in the Williston Basin. As of December 31, 2014, we had 72 gross operated wells waiting on completion in the Bakken and Three Forks formations. Our 2015 drilling plan, which was finalized when WTI was projected to average $50.41 per

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barrel, contemplates completing approximately 79 gross (63.3 net) operated wells in our project areas. We have the ability to increase or decrease the number of wells drilled and the number of wells completed during 2015 based on market conditions and program results.

- Enhance returns by focusing on operational and cost efficiencies. Our management team is focused on continuous improvement of our operations and has significant experience in successfully converting early-stage resource conversion opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas has and will continue to provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad into multiple formations, utilizing centralized production and oil, gas and water fluid handling facilities and infrastructure, and reducing the time and cost of rig mobilization. In addition, OWS expanded to two fracturing fleets in 2014, and we expect OWS and OMS to continue to provide capital savings and lower our operated well costs going forward compared to third party providers.
- Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize overall well economics. We believe these techniques have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of techniques such as drilling longer laterals, more tightly spaced fracturing stimulation stages and high intensity completions. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This continued evolution may enhance our initial production rates, increase ultimate recovery factors, lower well capital costs and improve rates of return on invested capital.
- Maintain financial flexibility. Based on current market conditions, we have a strong liquidity position. As of December 31, 2014, we had $500.0 million of borrowings and $5.2 million of outstanding letters of credit under our revolving credit facility and $1,040.6 million of liquidity available, including $45.8 million in cash and cash equivalents and $994.8 million of unused borrowing base committed capacity available under our revolving credit facility. On September 30, 2014, our borrowing base increased from $1,750.0 million to $2,000.0 million. However, at that time we elected to limit the lenders' aggregate commitment to $1,500.0 million. The next redetermination of the borrowing base is scheduled for April 1, 2015, and we currently expect the borrowing base to remain above our elected commitment amount of $1,500.0 million. Our liquidity position, along with internally generated cash flows from operations and settlements from our derivative contracts in 2015, will provide continued financial flexibility as we actively manage the pace of development on our acreage position in the Williston Basin. We also currently believe we have access to the public equity and debt markets, and we intend to maintain a balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise. We are also evaluating options to monetize certain assets in our portfolio, which could result in increased liquidity and lower leverage.
- Pursue strategic acquisitions with significant resource potential. As opportunities arise, we intend to identify and acquire additional acreage and producing assets in the Williston Basin to supplement our existing operations. Going forward, we may selectively target additional basins that would allow us to employ our resource conversion strategy on large undeveloped acreage positions similar to what we have accumulated in the Williston Basin.

Our competitive strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

- Substantial leasehold position in one of North America’s leading unconventional oil-resource plays. As of December 31, 2014, substantially all of our 505,503 net leasehold acres in the Williston Basin were highly prospective in the Bakken and Three Forks formations and 87% of our 272.1 MMBoe estimated net proved reserves in this area were comprised of oil. In addition, we have 433,794 net acres held-by-production as of December 31, 2014. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations, and much of our acreage is in areas of significant drilling activity by other exploration and production companies. In 2015, we are concentrating our drilling activities in the deepest part of the Williston Basin and expect to increase per well capital efficiency through our focused development efforts coupled with lower service costs from OWS and third party vendors.

- Large, multi-year project inventory. We believe we have a large inventory of potential drilling locations that we have not yet drilled, a majority of which are operated by us. We plan to slow the pace of completions in 2015 to 79 gross (63.3 net) operated wells in the Williston Basin in order to maintain financial flexibility and preserve the value of our inventory.
- Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry. Our senior technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our

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team's proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, our technical team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs.

- Incentivized management team. As of December 31, 2014, our executive officers owned 4% of our outstanding common stock, and an average of 73% of their overall compensation was in long-term equity-based incentive awards. We believe our executive officers' ownership interest in us provides them with significant incentives to grow the value of our business for the benefit of all stakeholders.
- Operating control over the majority of our portfolio. In order to maintain better control over our asset portfolio, we have established a leasehold position comprised primarily of properties that we expect to operate. As of December 31, 2014, 97% of our estimated net proved reserves were attributable to properties that we expect to operate. Approximately 96% of our 2015 drilling and completion capital expenditure budget is related to operated wells. As of December 31, 2014, our average working interest in our operated potential drilling locations was 68%. Controlling operations will allow us to dictate the pace of development and better manage the costs, type and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage will allow us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing hydrocarbon recovery through continuous improvement of drilling and completion techniques. We are also better able to control infrastructure investment to drive down operating costs, optimize oil price realizations and increase the monetization of gas production.

Our operations

Estimated net proved reserves

The table below summarizes our estimated net proved reserves and related PV-10 at December 31, 2014, 2013 and 2012 for each of our project areas based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated 100% of the reserves and discounted values at December 31, 2014, 2013 and 2012 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure do not include probable or possible reserves and were determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month prices. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The information in the following table does not give any effect to or reflect our commodity derivatives. Future operating costs, production taxes and capital costs were based on current costs as of each year-end. For a definition of proved reserves under the SEC rules, please see the "Glossary of oil and natural gas terms" included at the end of this report. For more information regarding our independent reserve engineers, please see "Independent petroleum engineers" below.

Project area	At December 31, 2014		At December 31, 2013		At December 31, 2012	
	Proved reserves (MMBoe)	PV-10[(1)] (in millions)	Proved reserves (MMBoe)	PV-10[(1)] (in millions)	Proved reserves (MMBoe)	PV-10[(1)] (in millions)
West Williston	197.8	$3,927.4	154.0	$3,571.0	94.6	$2,066.6
East Nesson	74.3	1,554.0	65.3	1,663.4	41.4	975.6
Sanish[(2)]	—	—	8.6	252.5	7.3	202.1
Total	272.1	$5,481.4	227.9	$5,486.9	143.3	$3,244.3

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable financial measure under accounting principles generally accepted in the United States of America ("GAAP"), because it does not include the effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See "Reconciliation of PV-10 to

Standardized Measure" below.

(2) Represents data related to non-operated properties in our Sanish project area, which were sold in the Sanish Divestiture in March 2014.

Estimated net proved reserves at December 31, 2014 were 272.1 MMBoe, a 19% increase from estimated net proved reserves of 227.9 MMBoe at December 31, 2013 primarily as a result of our 2014 drilling program and well completions, partially offset

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by the Sanish Divestiture during the year ended December 31, 2014. Our proved developed reserves increased 24.2 MMBoe, or 20%, to 146.3 MMBoe for the year ended December 31, 2014 from 122.1 MMBoe for the year ended December 31, 2013, primarily due to our 2014 drilling program, including the completion of 195 gross (147.4 net) operated wells. Our proved undeveloped reserves increased to 125.7 MMBoe for the year ended December 31, 2014 from 105.8 MMBoe for the year ended December 31, 2013, primarily due to our 2014 drilling program and changes to align our proved undeveloped reserves with our anticipated five-year drilling plan.

Estimated net proved reserves at December 31, 2013 were 227.9 MMBoe, a 59% increase from estimated net proved reserves of 143.3 MMBoe at December 31, 2012 primarily as a result of our 2013 drilling program and well completions as well as our four distinct acquisitions during 2013 of oil and natural gas properties in and around our West Williston and East Nesson project areas (the "2013 Acquisitions"). Our proved developed reserves increased 52.1 MMBoe, or 74%, to 122.1 MMBoe for the year ended December 31, 2013 from 70.0 MMBoe for the year ended December 31, 2012, primarily due to our 2013 drilling program, including the completion of 136 gross (106.1 net) operated wells, and our property acquisitions. Our proved undeveloped reserves increased to 105.8 MMBoe for the year ended December 31, 2013 from 73.3 MMBoe for the year ended December 31, 2012, primarily due to our 2013 drilling program and the 2013 Acquisitions.

The following table sets forth more information regarding our estimated net proved reserves at December 31, 2014, 2013 and 2012:

	At December 31,		
	2014	2013	2012
Reserves Data[1]:			
Estimated proved reserves:			
Oil (MMBbls)	235.4	198.6	128.1
Natural gas (Bcf)	220.1	176.0	91.5
Total estimated proved reserves (MMBoe)	272.1	227.9	143.3
Percent oil	87 %	87 %	89 %
Estimated proved developed reserves:			
Oil (MMBbls)	127.3	106.8	62.6
Natural gas (Bcf)	114.0	92.2	44.7
Total estimated proved developed reserves (MMBoe)	146.3	122.1	70.0
Percent proved developed	54 %	54 %	49 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	108.1	91.8	65.5
Natural gas (Bcf)	106.1	83.8	46.8
Total estimated proved undeveloped reserves (MMBoe)	125.7	105.8	73.3
PV-10 (in millions)[2]	$5,481.4	$5,486.9	$3,244.3
Standardized Measure (in millions)[3]	$3,981.7	$3,727.6	$2,259.9

(1) Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $95.28/Bbl for oil and $4.35/MMBtu for natural gas, $96.96/Bbl for oil and $3.66/MMBtu for natural gas and $94.68/Bbl for oil and $2.75/MMBtu for natural gas for the years ended December 31, 2014, 2013 and 2012, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Future operating costs, production taxes and capital costs were based on current costs as of each year-end.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effect of income taxes on discounted future

net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See "Reconciliation of PV-10 to Standardized Measure" below.

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(3) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2014, 2013 and 2012:

	At December 31,		
	2014	2013	2012
		(In millions)	
PV-10	$5,481.4	$5,486.9	$3,244.3
Present value of future income taxes discounted at 10%	1,499.7	1,759.3	984.4
Standardized Measure of discounted future net cash flows	$3,981.7	$3,727.6	$2,259.9

The PV-10 of our estimated net proved reserves at December 31, 2014 was $5,481.4 million. PV-10 remained essentially unchanged from PV-10 of $5,486.9 million at December 31, 2013, primarily due to lower realized prices and higher costs, which were offset by an increase in reserves year over year.

Estimated future net revenues

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2014, 2013 and 2012:

	At December 31,		
	2014	2013	2012
	(In millions, except price data)		
Future net revenues	$11,999.3	$11,685.6	$7,077.4
Present value of future net revenues:			
Before income tax (PV-10)	5,481.4	5,486.9	3,244.3
After income tax (Standardized Measure)	3,981.7	3,727.6	2,259.9
Benchmark oil price ($/Bbl)[1]	$95.28	$96.96	$94.68

(1) Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $95.28/Bbl for oil and $4.35/MMBtu for natural gas, $96.96/Bbl for oil and $3.66/MMBtu for natural gas and $94.68/Bbl for oil and $2.75/MMBtu for natural gas for the years ended December 31, 2014, 2013 and 2012, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at

the wellhead. Future operating costs, production taxes and capital costs were based on current costs as of each year-end.

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Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2014, 2013 and 2012 are based on costs in effect at December 31 of each year and the twelve-month unweighted arithmetic average of the first-day-of-the-month price for January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. As of February 17, 2015, spot crude oil and natural gas prices have decreased approximately 50% and 40%, respectively, since June 2014. An extended period of low prices for oil could result in a significant decrease in our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure in the future. There are numerous uncertainties inherent in estimating reserves and related information, and different reservoir engineers often arrive at different estimates for the same properties.

Proved undeveloped reserves

At December 31, 2014, we had approximately 125.7 MMBoe of proved undeveloped reserves as compared to 105.8 MMBoe at December 31, 2013.

The following table summarizes the changes in our proved undeveloped reserves during 2014 (in MBoe):

At December 31, 2013	105,784
Extensions, discoveries and other additions	58,192
Purchases of minerals in place	755
Sales of minerals in place	(290)
Revisions of previous estimates	(20,372)
Conversion to proved developed reserves	(18,326)
At December 31, 2014	125,743

During 2014, we spent a total of $394.9 million related to the development of proved undeveloped reserves, $84.4 million of which was spent on proved undeveloped reserves that represent wells in progress at year-end. The remaining $310.5 million resulted in the conversion of 18,326 MBoe of proved undeveloped reserves, or 17% of our proved undeveloped reserves balance at the beginning of 2014, to proved developed reserves. We added 58,192 MBoe of proved undeveloped reserves in our West Williston and East Nesson project areas as a result of our 2014 operated and non-operated drilling program and anticipated five-year drilling plan. We participated in 269 gross (151.1 net) wells that were completed and brought on production during 2014. In addition, we purchased 755 MBoe of proved undeveloped reserves primarily as a result of acquisitions, acreage additions and trades during the year ended December 31, 2014. In 2014, we sold a total of 290 MBoe proved undeveloped reserves in the Sanish Divestiture. In 2014, our net negative revision of 20,372 MBoe, or 19% of our December 31, 2013 proved undeveloped reserves balance, is primarily due to the removal of proved undeveloped reserves not aligned with our anticipated five-year drilling plan, which was adjusted to allocate a greater focus on higher rates-of-return areas of the Bakken and Three Forks formations. This resulted in 80 (56.2 net) proved undeveloped locations with 21,411 MBoe of reserves being removed from the December 31, 2014 estimated net proved reserves balance.

We expect to develop all of our proved undeveloped reserves as of December 31, 2014 within five years of their initial booking. The future development of such proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our revolving credit facility and derivative contracts. All proved undeveloped locations are located on properties where the leases are held by existing production, by continuous drilling operations, or associated with leases not expiring within the next five years.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2014, 2013 and 2012 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves

Information (Revision as of February 19, 2007) and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary, Moscow and Algiers. The firm's more than 100 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and

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international energy industry. DeGolyer and MacNaughton has provided such services for over 75 years. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Professional Engineer in the State of Texas with over 30 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from The University of Texas at Austin in 1984, and he is a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of oil and natural 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. The term "reasonable certainty" means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated net proved reserves, DeGolyer and MacNaughton employed technologies including, but not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available down hole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the Bakken and Three Forks formations were used to estimate original oil in place. In areas where estimated proved reserves were attributed to more than one well per spacing unit, the estimated original oil in place was used to calculate reasonable estimated recovery factors based on experience with similar reservoirs where similar drilling and completion techniques have been employed.

Internal controls over reserves estimation process

We employ DeGolyer and MacNaughton as the independent reserves evaluator for 100% of our reserves base. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with the independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished for the reserves estimation process. Brett Newton, Senior Vice President of Asset Management and Chief Engineer, is the technical person primarily responsible for overseeing our reserves evaluation process. He has 25 years of industry experience with positions of increasing responsibility in engineering and management. He holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Mr. Newton reports directly to our President and Chief Operating Officer.

Throughout each fiscal year, our technical team meets with the independent reserve engineers to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;

- Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineers;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management and Chief Engineer;

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- Review of a preliminary copy of the reserve report by our President and Chief Operating Officer with our internal technical staff; and
- Review of our reserves estimation process by our Audit Committee on an annual basis.

Production, revenues and price history

We produce and market oil and natural gas, which are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past few years, and this has contributed to a current global oversupply of crude oil, which has caused a sharp decline in oil prices in recent months. As of February 17, 2015, spot crude oil and natural gas prices have decreased approximately 50% and 40%, respectively, since June 2014. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2014	2013	2012
Net production volumes:			
Oil (MBbls)	14,883	11,133	7,533
Natural gas (MMcf)	10,691	7,450	4,146
Oil equivalents (MBoe)	16,664	12,375	8,224
Average daily production (Boe/d)	45,656	33,904	22,469
Average sales prices:			
Oil, without derivative settlements (per Bbl)	$82.73	$92.34	$85.22
Oil, with derivative settlements (per Bbl)[1]	83.19	91.61	86.09
Natural gas (per Mcf)[2]	6.81	6.78	6.52
Costs and expenses (per Boe of production):			
Lease operating expenses	$10.18	$7.65	$6.68
Marketing, transportation and gathering expenses	1.75	2.09	1.13
Production taxes	7.66	8.12	7.66
Depreciation, depletion and amortization	24.74	24.81	25.14
General and administrative expenses	5.54	6.09	6.95

(1) Realized prices include gains or losses on cash settlements for our commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(2) Natural gas prices include the value for natural gas and natural gas liquids.

Net production volumes for the year ended December 31, 2014 were 16,664 MBoe, a 35% increase from net production of 12,375 MBoe for the year ended December 31, 2013. Our net production volumes increased 4,289 MBoe over 2013 primarily due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without derivative settlements, decreased by $9.61/Bbl, or 10%, to an average of $82.73/Bbl for the year ended December 31, 2014 as compared to the year ended December 31, 2013. Giving effect to our

derivative transactions in both periods, our oil sales prices decreased $8.42/Bbl to $83.19/Bbl for the year ended December 31, 2014 from $91.61/Bbl for the year ended December 31, 2013.

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Net production volumes for the year ended December 31, 2013 were 12,375 MBoe, a 50% increase from net production of 8,224 MBoe for the year ended December 31, 2012. Our net production volumes increased 4,151 MBoe over 2012 due to a successful operated and non-operated drilling and completion program and acquisitions of producing properties. Average oil sales prices, without derivative settlements, increased by $7.12/Bbl, or 8%, to an average of $92.34/Bbl for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Giving effect to our derivative transactions in both periods, our oil sales prices increased $5.52/Bbl to $91.61/Bbl for the year ended December 31, 2013 from $86.09/Bbl for the year ended December 31, 2012.

The following table sets forth information regarding our average daily production for the years ended December 31, 2014, 2013 and 2012:

	Average daily production for the years ended December 31,								
	2014			2013			2012		
Project area	Bbls	Mcf	Boe	Bbls	Mcf	Boe	Bbls	Mcf	Boe
West Williston	27,198	20,573	30,627	18,815	14,127	21,170	13,904	8,152	15,263
East Nesson	13,228	8,478	14,641	9,229	4,951	10,054	4,586	2,106	4,936
Sanish[(1)]	348	238	388	2,458	1,333	2,680	2,091	1,070	2,270
Total	40,774	29,289	45,656	30,502	20,411	33,904	20,581	11,328	22,469

(1) Represents data related to non-operated properties in our Sanish project area, which were sold in the Sanish Divestiture in March 2014.

Productive wells

The following table presents the total gross and net productive wells by project area as of December 31, 2014:

	Total wells		Bakken and Three Forks		Operated Bakken and Three Forks wells	
Project area	Gross	Net	Gross	Net	Gross	Net
West Williston	776	443.9	629	342.7	431	327.5
East Nesson	344	185.1	344	185.1	220	177.1
Total	1,120	629.0	973	527.8	651	504.6

All of our productive wells are oil wells. Gross wells are the number of wells, operated and non-operated, in which we own a working interest and net wells are the total of our working interests owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2014 for each of our project areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed acres		Undeveloped acres		Total acres	
Project area	Gross	Net	Gross	Net	Gross	Net
West Williston	349,697	265,015	135,224	92,569	484,921	357,584
East Nesson	135,213	101,138	71,221	46,781	206,434	147,919
Total	484,910	366,153	206,445	139,350	691,355	505,503

We increased our acreage that is held-by-production to 433,794 net acres at December 31, 2014 from 422,386 net acres at December 31, 2013.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2014 that will expire over the next three years by project area unless production is established within the spacing units covering the acreage prior to the expiration dates:

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	Expiring 2015		Expiring 2016		Expiring 2017	
Project area	Gross	Net	Gross	Net	Gross	Net
West Williston	6,917	5,430	8,821	3,155	8,119	7,046
East Nesson	26,049	19,267	25,556	15,080	7,603	5,773
Total	32,966	24,697	34,377	18,235	15,722	12,819

Drilling and completion activity

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013 and 2012. Gross wells reflect the sum of all productive and dry wells, operated and non-operated, in which we own an interest. Net wells reflect the sum of our working interests in gross wells. The gross and net wells represent wells completed during the periods presented, regardless of when drilling was initiated.

	Year ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	188	102.6	188	75.3	193	89.9
Gas	—	—	—	—	—	—
Dry[(1)]	—	—	—	—	2	1.9
Total development wells	188	102.6	188	75.3	195	91.8
Exploratory wells:						
Oil	81	48.5	62	39.8	38	15.7
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	81	48.5	62	39.8	38	15.7
Total wells	269	151.1	250	115.1	233	107.5

(1) In 2012, we had two gross development dry hole wells as a result of mechanical failures. Replacement wells were drilled in the same drilling spacing units and were productive wells.

Our drilling activity has increased each year since our inception. In 2012 and 2013, we focused on delineation and appraisal of the Bakken and Three Forks formations, resulting in substantially all of our acreage being delineated as of December 31, 2013. In 2014, we focused on full field development in our West Williston and East Nesson project areas. We also continued to participate in a number of wells on a non-operated basis.

We did not drill any dry hole wells in 2014 or 2013. In 2012, we had two gross development dry hole wells as a result of mechanical failures. Replacement wells were drilled in the same drilling spacing units and were productive wells. In 2012, we allocated a portion of the costs for a well that was unsuccessful due to mechanical complications in the Three Forks formation to exploratory dry hole expense. The well was successfully plugged back and completed in the Bakken formation.

As of December 31, 2014, we had 15 operated rigs running, 28 gross (18.0 net) operated wells drilling on multi-well pads and an inventory of 72 gross operated wells waiting on completion. Consistent with our 2015 capital plan, we expect to continue to focus on drilling in the Bakken and Three Forks formations.

Capital expenditure budget

In 2014, we spent $1,572.6 million on capital expenditures, which represented a 37% decrease from the $2,506.3 million spent during 2013. Excluding acquisitions totaling $37.2 million in 2014 and $1,563.4 million in 2013, our capital expenditures increased 63% year over year. The increase, excluding the impact of acquisitions, was due to more drilling and completion activity coupled with higher capital expenditures for OMS, primarily related to pipelines and salt water disposal wells, and for OWS, primarily related to adding a second fracturing fleet. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Cash flows used in investing activities.”

We have significantly decreased our planned 2015 capital expenditures as compared to 2014 as a result of current lower commodity prices. Our total 2015 capital expenditure budget is $705 million, which includes $678 million for exploration and

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production ("E&P") capital expenditures and $27 million for non-E&P capital expenditures, including OWS, administrative capital and capitalized interest. We plan to complete approximately 79 gross (63.3 net) operated wells and participate in 2.6 net non-operated wells that are expected to be completed and brought on production in 2015. Our planned E&P capital expenditures include $565 million of drilling and completion (including production-related equipment) capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS).

While we have budgeted $705 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. Additionally, if we acquire additional acreage, our capital expenditures may be higher than budgeted. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources."

Our core project areas

Williston Basin

Our operations are focused in the North Dakota and Montana areas of the Williston Basin. While we have interests in a substantial number of wells in the Williston Basin that target several different zones, our exploration and development activities are currently concentrated in the Bakken and Three Forks formations. Our management team originally targeted the Williston Basin because of its oil-prone nature, multiple producing horizons, substantial resource potential and management's previous professional history in the basin. The Williston Basin also has established infrastructure and access to materials and services.

The entire Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada. The basin produces oil and natural gas from numerous producing horizons including, but not limited to, the Bakken, Three Forks, Madison and Red River formations. A report issued by the United States Geological Survey in April 2008 classified these formations as the largest continuous oil accumulation ever assessed by it in the contiguous United States. The Williston Basin is now one of the most actively drilled unconventional oil resource plays in the United States, with over 200 rigs drilling in the basin during 2014, although more recently the active rig count has decreased to 135 as of February 17, 2015 due to the decline in oil prices.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members including the upper shale, middle Bakken and lower shale. The formation ranges up to 150 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The middle Bakken, which varies in composition from a silty dolomite to shaley limestone or sand, also serves as a reservoir and is a critical component for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results and publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock that may add incremental reserves to our existing leasehold positions. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as Sanish sand. The Three Forks formation is an unconventional carbonate play. Based on our geologic interpretation of the Three Forks formation, the evolution of completion techniques, our own drilling results and publicly available drilling results for other operators in the basin, we believe that much of our Williston Basin acreage is prospective in the Three Forks formation.

Our total leasehold position in the Williston Basin as of December 31, 2014 consisted of 505,503 net acres. Our estimated net proved reserves in the Williston Basin were 272.1 MMBoe at December 31, 2014. Of our estimated net proved reserves in the Williston Basin, approximately 146.3 MMBoe were proved developed reserves, which are comprised of a combination of wells drilled to conventional reservoirs, Bakken and Three Forks wells drilled with older completion techniques, and to a much larger extent, Bakken and Three Forks wells drilled with completion techniques similar to those we currently employ. Of our estimated net proved reserves, 125.7 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three Forks wells to be drilled with more recent completion techniques. We expect that all of our potential drilling locations in each of our project areas will be drilled

and completed using completion techniques similar to those we currently employ. As of December 31, 2014, we had a total of 629.0 net operated and non-operated producing wells and 600.2 net operated producing wells in the Williston Basin. We had average daily production of 45,656 net Boe/d for the year ended December 31, 2014 in the Williston Basin. During 2014, our Bakken and Three Forks wells produced a daily average of 44,667 net Boe/d with 527.8 net producing wells on December 31, 2014. Accordingly, our 527.8 net Bakken and Three Forks wells were responsible for 98% of our average daily production during 2014. As of December 31, 2014, our working interest for all producing wells averaged 56% and in the wells we operate was approximately 79%. As of December 31, 2014, we were drilling or completing 118 gross (74.8 net) wells in the Williston Basin. We participated in 269 gross (151.1 net) wells that were completed and brought on production during 2014.

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Our Williston Basin activities are evaluated in two primary areas of operations: West Williston and East Nesson. Prior to the Sanish Divestiture in March 2014, Sanish was our third primary area of operations in the Williston Basin.

West Williston

We control 357,584 net acres in the West Williston project area, primarily in Williams and McKenzie counties in North Dakota and Roosevelt and Richland counties in Montana. We had average daily production of 30,627 net Boe/d for the year ended December 31, 2014, 97% of which was produced from the Bakken and Three Forks formations and the remainder from other conventional formations. As of December 31, 2014, we had an average working interest of 57% and operated 95% of our 443.9 net producing wells in the West Williston project area. As of December 31, 2014, we operated 95% of our 342.7 net producing Bakken and Three Forks wells in the West Williston project area.

During the year ended December 31, 2014, our total completions were 168 gross (89.8 net) horizontal Bakken and Three Forks wells in the West Williston project area. As of December 31, 2014, we were participating in the drilling or completion of 75 gross (47.9 net) wells in this project area. We have budgeted $451 million in capital expenditures in the West Williston project area in 2015 for the completion of 57 gross (45.0 net) operated wells and 2.6 net non-operated wells.

East Nesson

We control 147,919 net acres in the East Nesson project area, primarily in Mountrail and Burke counties in North Dakota. We had average daily production of 14,641 net Boe/d for the year ended December 31, 2014, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2014, we had an average working interest of 54% and operated 96% of our 185.1 net producing wells in the East Nesson project area, all of which are producing out of the Bakken and Three Forks formations.

During the year ended December 31, 2014, our total completions were 101 gross (61.3 net) horizontal Bakken and Three Forks wells in the East Nesson project area. As of December 31, 2014, we were participating in the drilling or completion of 43 gross (26.9 net) wells in this project area. We have budgeted $114 million in capital expenditures in the East Nesson project area in 2015 for the completion of 22 gross (18.3 net) operated wells and no net non-operated wells.

Sanish

On March 5, 2014, we completed the Sanish Divestiture, in which we divested of certain properties in and around our Sanish project area. Our properties in this project area, located in Mountrail County in North Dakota, were entirely operated by other operators. We had average daily production of 388 net Boe/d for the year ended December 31, 2014, all of which was produced from the Bakken and Three Forks formations.

Please see Note 7 to our audited consolidated financial statements for a description of the Sanish Divestiture.

Marketing, transportation and major customers

The Williston Basin crude oil rail and pipeline transportation and refining infrastructure has grown substantially in recent years, largely in response to drilling activity in the Bakken and Three Forks formations. In December 2014, oil production in North Dakota was approximately 1,227,000 barrels per day compared to approximately 927,000 barrels per day in December 2013. According to the North Dakota Pipeline Authority website’s data dated January 14, 2015, there was approximately 773,000 barrels per day of crude oil pipeline transportation capacity in the Williston Basin as of December 31, 2014. In addition, there was approximately 1,260,000 barrels per day of specifically dedicated railcar transportation capacity as of December 31, 2014. In 2014, we continued to sell a significant amount of our crude oil production from our West Williston and East Nesson project areas through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which typically originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of December 31, 2014, we were flowing approximately 75% of our gross operated oil production through these gathering systems.

Recent expansion of both rail and pipeline facilities has reduced the previous constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. However, oil from Canada has continued to flow into the existing downstream pipeline infrastructure that services Midwest refineries and affects Williston Basin pipeline sales demand into those Midwest refineries. Both Canadian oil and Williston Basin crude oil continue to utilize these pipeline facilities, and excess pipeline capacity is available due to the current balance between rail and pipeline capacity. For a discussion of the potential risks to our business that could result from transportation and

refining infrastructure constraints in the Williston Basin, please see “Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.”

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We principally sell our oil and natural gas production to refiners, marketers and other purchasers that have access to nearby pipeline and rail facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production" and "Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices."

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

For the years ended December 31, 2014, 2013 and 2012, sales to Musket Corporation accounted for approximately 13%, 11% and 10% of our total sales, respectively. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2014, 2013 and 2012. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil and natural gas purchasers in our project areas.

As of December 31, 2014, we sold a substantial majority of our oil and condensate through bulk sales from delivery points on crude oil gathering systems or directly at the wellhead to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market-based price, which incorporates regional differentials that include, but are not limited to, transportation costs and adjustments for product quality. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the price quoted for WTI crude oil due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. In the first half of 2012, price differentials were at or above the historical average discount range of 10% to 15% to the price quoted for WTI crude oil due to production growth in the Williston Basin combined with refinery and transportation constraints. In the third quarter of 2012, our average price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium received in coastal markets contracted during the second and third quarters of 2013, our average price differentials relative to WTI increased. In the fourth quarter of 2013 and into the first quarter of 2014, our average price differentials to WTI continued to increase due to the pipeline market weakening as a result of refinery down time and increased United States and Canadian production. In the second and third quarters of 2014, stronger pipeline prices shifted more of our barrels towards the pipelines, but rail buyers had to compete with pipeline prices despite weaker Brent differentials, and our price differentials to WTI returned to approximately 9% to 11%. In the fourth quarter of 2014, as WTI crude oil prices declined, our price differentials increased as a percentage of WTI but remained relatively flat in terms of the dollar per barrel discount to WTI in the range of $9.00 to $10.50 per barrel of oil. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

Since most of our oil and natural gas production is sold under market-based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, the condition of the United States economy, oil supply in the United States, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of the Organization of Petroleum Exporting Countries, or OPEC, and domestic government regulation, legislation and policies. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital

expenditure obligations and financial commitments." Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flows. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties." Market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production."

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Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please see “Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.”

Title to properties

As is customary in the oil and gas industry, we initially conduct a preliminary review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant title defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with general industry standards. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our revolving credit facility, liens for current taxes and other burdens, which we believe do not materially interfere with the use or affect our carrying value of the properties. Please see “Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—We may incur losses as a result of title defects in the properties in which we invest.”

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial

compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by

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Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access 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 transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 16, 2010, the FERC established a new price index for the five-year period beginning July 1, 2011.

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 who are similarly situated.

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 similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally 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 similarly situated competitors.

We sell a significant amount of our crude oil production through gathering systems connected to rail facilities. Several recent derailments of freight trains, including the events in July 2013 in Lac Mégantic, have led federal and state regulators to examine whether the hazardous nature of crude oil from the Bakken shale is being assessed properly prior to its shipment. In particular, there are concerns that the testing and ensuing designations of the crude oil on the shipping documentation do not in all cases accurately capture the flammability of the Bakken crude oil. On January 2, 2014, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") released a Safety Alert alerting regulators, emergency responders, transporters and shippers that crude oil from the Bakken Shale may have flammability characteristics that are different from other forms of crude oil and that it was vital that all shipments of crude oil be tested and properly characterized on all shipping documentation. The Safety Alert also notified the regulated community that PHMSA and the Federal Railroad Administration have launched "Operation Classification," which is an ongoing enforcement initiative that involves unannounced inspections on crude oil shipments to test the contents of the shipments in order to ensure that they are properly characterized. In August 2014, the U.S. Department of Transportation released a report finding that, based on the results of Operation Classification from August 2013 to May 2014, Bakken crude oil tends to be more volatile and flammable than other crude oils, and thus poses an increased risk for a significant accident.

In addition, these events have also spurred efforts to improve the safety of tank cars that are used in transporting crude oil by rail. Since 2011, all new railroad tank cars that have been built to transport crude oil or other petroleum type fluids (e.g., ethanol) have been built to more stringent safety standards. In August 2014, PHMSA issued a Notice of Proposed Rulemaking that proposes, among other things, additional requirements that would enhance tank car standards for certain trains carrying crude oil and ethanol, a classification and testing program for crude oil, and a requirement that older DOT-111 tank cars be phase out by as early as October 1, 2017 if they are not retrofitted to comply with new tank car design standards. The proposed rule also includes new operational requirements for certain trains, including route analyses, improved braking controls and speed restrictions. In conjunction with the proposed rule, PHMSA published an Advanced Notice of Proposed Rulemaking related to potential revisions to its regulations

that would expand the applicability of comprehensive oil spill response plans to certain trains based on the thresholds of crude oil that apply to an entire train. The final rule is expected in early 2015. Were PHMSA to require safety improvements or updates to existing tank cars, that could drive up the cost of transport and lead to shortages in availability of tank cars. We do not currently own or operate rail transportation facilities or rail cars; however, we cannot assure that costs incurred by the railroad industry to comply with standards and regulations emerging from PHMSA's rulemaking process will not increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices, the consequences of which could be material to our business, financial condition or results of operations.

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However, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Efforts are likewise underway in Canada to assess and address risks from the transport of crude oil by rail. Shortly after the Lac Mégantic tragedy, Transport Canada issued a series of emergency directives aimed at certain practices that were identified immediately after the accident. Likewise, Transport Canada is assessing the compensation and liability scheme for shipments by rail so that sufficient funds are available to compensate victims and respond to the incident without making taxpayers fund any aspect of those efforts. In January 2014, the Canadian Transportation Safety Board made several recommendations to Transport Canada regarding tank car safety, routing of freight trains and the capabilities of emergency responders. In April 2014, Transport Canada issued a protective order prohibiting oil shippers from using 5,000 of the DOT-111 tank cars and imposing a three-year phase out period for approximately 65,000 tank cars that do not meet certain safety requirements. Transport Canada also imposed a 50 mile-per-hour speed limit on trains carrying hazardous materials and required all crude oil shipments in Canada to have an emergency response plan.

We believe we are in substantial compliance with applicable hazardous materials transportation requirements related to our operations. We do not believe that compliance with federal, state or local hazardous materials transportation regulations will have a material adverse effect on our financial position or results of operations. However, future events, such as changes in existing laws (including changes in the interpretation of existing laws), the promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil, or the development or discovery of new facts or conditions could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices, the consequences of which could be material to our business, financial condition or results of operations. However, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 (“NGA”), the Natural Gas Policy Act of 1978 (“NGPA”) and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines’ traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC’s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC’s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. 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 under Order No. 637 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.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"). Please see below the discussion of "Other federal laws and regulations affecting our industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year

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for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please see below the discussion of "Other federal laws and regulations affecting our industry—FERC Market Transparency Rules."

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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 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. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural 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 reports concerning operations. We own and operate properties in North Dakota and Montana, which have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural 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 natural 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, both states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions.

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

Other federal laws and regulations affecting our industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act,

practice or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

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FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

North Dakota Industrial Commission oil and gas rule changes. The North Dakota Industrial Commission has adopted more stringent rule changes to its existing oil and gas regulations. The rules became effective on April 1, 2012 and, among other things, impose relatively higher bonding amounts for the drilling of wells, severely restrict the discharge and storage of production wastes such as produced water, drilling mud, waste oil and other wastes in earthen pits, implement more stringent hydraulic fracturing requirements and require the provision of public disclosure on the national website, FracFocus.org, regarding chemicals used in the hydraulic fracturing process. Compliance with these recent rule changes by oil and natural gas exploration and production operators in general and us in particular increased our well costs during 2012, 2013 and 2014, and we expect to continue to incur these increased costs in order to remain in compliance.

In 2014, the North Dakota Industrial Commission adopted rules intended to reduce natural gas flaring. Please see below the discussion of "Environmental protection and natural gas flaring initiatives." In addition, on December 9, 2014, the North Dakota Industrial Commission adopted new conditioning standards to improve the safety of Bakken crude oil for transport. The rule becomes effective April 1, 2015 and sets operating standards for conditioning equipment to properly separate production fluids. The rule includes parameters for temperatures and pressures for production equipment. The rule also addresses limits to vapor pressure of produced crude oil.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental and occupational health and safety regulation

Our exploration, development and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment; limit or prohibit construction or drilling activities in environmentally-sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered species; require investigatory and remedial actions to mitigate pollution conditions; impose obligations to reclaim and abandon well sites and pits; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible.

The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or reinterpretation of applicable enforcement policies that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs

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and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental and occupational health and safety laws to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict 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. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We are also subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation, disposal and cleanup of hazardous and nonhazardous wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. RCRA currently exempts certain drilling fluids, produced waters and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes. These wastes, instead, are regulated under RCRA's less stringent nonhazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas exploration, development and production wastes now classified as nonhazardous wastes could be classified as hazardous wastes in the future. Repeal or modification of this RCRA exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the oil and natural gas industry in general. In the course of our operations, we generate ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons, hazardous substances and wastes may have been released on, under or from the properties owned or leased by us or on, under or from, other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons, hazardous substances and wastes were not under our control. These properties and the substances disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial plugging or pit closure operations to prevent future contamination.

Air emissions

The federal Clean Air Act, as amended ("CAA"), and comparable state laws and regulations restrict the emission of various air pollutants from many sources through air emissions standards, construction and operating permitting programs, and the imposition of other monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Obtaining permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in 2012, the EPA published final rules under the CAA that subject oil and

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natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells by using reduced emission completions, also known as "green completions," after January 1, 2015. These regulations also establish specific new requirements regarding emissions from certain production-related wet seal and reciprocating compressors, pneumatic controllers, and storage vessels. We review new rules such as these to assess their impact on our operations. Compliance with new requirements could increase our costs of development and production, which costs could be significant.

Environmental protection and natural gas flaring initiatives

We attempt to conduct our operations in a manner that protects the health, safety and welfare of the public, our employees and the environment. We are focused on the reduction of air emissions produced from our operations, particularly with respect to flaring of natural gas from our operated well sites. The rapid growth of crude oil production in North Dakota in recent years, coupled with a historical lack of natural gas gathering infrastructure in the state, has led to an industry-wide effort to reduce flaring of natural gas produced in association with crude oil production. We recognize the environmental and financial risks associated with natural gas flaring, and we seek to manage these risks on an ongoing basis and reduce flaring from our operated well sites.

We believe that one of the leading causes of natural gas flaring from the Bakken and Three Forks formations is the inability of operators to promptly connect their wells to natural gas processing and gathering infrastructure due to external factors out of the control of the operator, such as, for example, the granting of right-of-way access by land owners, investment from third parties in the development of gas gathering systems and processing facilities, and the development and adoption of regulations. However, we have allocated significant resources to connect our Bakken and Three Forks wells to natural gas infrastructure in a timely manner to reduce our flared volumes. We have exceeded a goal that we voluntarily set in 2014 to maintain well connections for an average of 90% of our operated Bakken and Three Forks wells during the year ending December 31, 2014 by having approximately 97% of our operated Bakken and Three Forks wells connected to gathering systems as of December 31, 2014. We believe that achieving this goal helps us to minimize our flared volumes of natural gas.

On July 1, 2014, the North Dakota Industrial Commission adopted Order No. 24665 (the "July 2014 Order"), pursuant to which the agency adopted legally enforceable "gas capture percentage goals" targeting the capture of 74% of natural gas produced in the state by October 1, 2014, 77% of such gas by January 1, 2015, 85% of such gas by January 1, 2016 and 90% of such gas by October 1, 2020. The July 2014 Order establishes an enforcement mechanism for policy recommendations that were previously adopted by the North Dakota Industrial Commission in March 2014. Those recommendations required all exploration and production operators applying for new drilling permits in the state after June 1, 2014 to develop Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency's now-implemented gas capture percentage goals. In particular, the July 2014 Order provides that after an initial 90-day period, wells must meet or exceed the North Dakota Industrial Commission's gas capture percentage goals on a per-well, per-field, county, or statewide basis. Failure to comply with the gas capture percentage goals will result in an operator having to restrict its production to 200 barrels of oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or 100 barrels of oil per day if less than 60% of such monthly volume of natural gas is captured. While we believe that we were in compliance with these requirements as of December 31, 2014 and expect to remain in compliance in the future, there is no assurance that we will be able to remain in compliance in the future or that such future compliance will not have a material adverse effect on our business and operation results.

Climate change

Based on findings made by the EPA in 2009 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 contributing to warming of the Earth's atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the CAA that establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG

emissions also will be required to meet “best available control technology” standards, which typically will be established by the states. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

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While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas facilities, including production facilities, as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act, as amended (the "Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and 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 the analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. 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, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act, and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under the OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Operations associated with our production and development activities generate drilling muds, produced waters and other waste streams, some of which may be disposed of by means of injection into underground wells situated in non-producing subsurface formations. North Dakota Industrial Commission rule changes effective in 2012 severely restrict the discharge and storage of production wastes including produced water in earthen pits, which increases the likelihood that injection wells are used to dispose of appropriate waste streams. These injection wells are regulated by the federal Safe Drinking Water Act and analogous state laws. The underground injection well program under the Safe Drinking Water Act requires permits from the EPA or analogous state agency for disposal wells that we operate, establishes minimum standards for injection well operations and restricts the types and quantities of fluids that may be injected. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries. While we

believe that we are in substantial compliance with applicable disposal well requirements, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

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Hydraulic fracturing activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional formations, including shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

From time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We have obtained an insurance policy that is intended to provide coverage for gradual pollution losses related to hydraulic fracturing operations. Additionally, we believe our general liability and excess liability insurance policies would generally cover third-party claims directly related to hydraulic fracturing operations conducted by third parties and associated legal expenses in accordance with, and subject to, the terms of such policies. However, certain long term pollution and environmental risks are not fully insurable. Please see "Item 1A. Risk Factors—We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks."

Endangered Species Act considerations

The federal Endangered Species Act, as amended ("ESA"), may restrict exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits the

taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on a listing of numerous species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in

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areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

Operations on federal lands

Performance of oil and gas exploration and production activities on federal lands, including Indian lands and lands administered by the federal BLM are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Depending on any mitigation strategies recommended in such environmental assessments or environmental impact statements, we could incur added costs, which could be substantial, and be subject to delays or limitations in the scope of oil and natural gas projects.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Employees

As of December 31, 2014, we employed 558 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2014, we leased 111,628 square feet of office space in Houston, Texas at 1001 Fannin Street, where our principal offices are located. The lease for our Houston office expires in September 2020. We also own field offices in the North Dakota communities of Williston, Powers Lake and Alexander.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange ("NYSE") under the symbol "OAS." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.oasispetroleum.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

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Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. 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. For example, average daily prices for WTI crude oil ranged from a high of $107.95 per barrel to a low of $53.45 per barrel during 2014. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $8.15 per MMBtu to a low of $2.74 per MMBtu during 2014. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America, China, India and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. Low oil and natural gas prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. See "Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves." Low oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also "The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves" below.

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 financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations 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. For a discussion of the uncertainty involved in these processes, see "Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any

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significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves" below. 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 our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions and/or failure;
- unexpected operational events, including accidents;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards, ice storms and floods;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

Our estimated net proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant 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 current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See "Item 1. Business—Our operations" for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2014, 2013 and 2012.

In order to prepare our estimates, we must project production rates and the 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 oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. In addition, we may adjust estimates of net 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. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

The present value of future net revenues from our estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our estimated net proved reserves is the current market value of our estimated net oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2014, 2013 and 2012, we based the estimated discounted future net revenues from our estimated net proved reserves on the twelve-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;

- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

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The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from estimated net proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. Any significant future price changes will have a material effect on the quantity and present value of our estimated net proved reserves.

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

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services or the unavailability of sufficient transportation for our production could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations. Additionally, compliance with new or emerging legal requirements that affect midstream operations in North Dakota may reduce the availability of transportation for our production. For example, the North Dakota Industrial Commission adopted regulations in late 2013 that impose more rigorous pipeline development standards on midstream operators, some of whom we rely on to construct and operate pipeline infrastructure to transport the oil and natural gas we produce.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Operations in the Bakken and the Three Forks formations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Bakken and Three Forks formations began in late 2009. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or oil and natural gas prices decline, the return on our investment in these areas may not be as attractive as we anticipate. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our estimated net oil and natural gas reserves.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. We spent $1,572.6 million and $2,506.3 million (including acquisitions) related to capital expenditures for the years ended December 31, 2014 and 2013, respectively. Our capital expenditure budget for 2015 is approximately $705 million, with approximately $565 million allocated for drilling and completion operations. Since

our IPO, our capital expenditures have been financed with proceeds from our IPO, proceeds from our $2,200.0 million of senior unsecured notes, net cash provided by operating activities, proceeds from our secondary equity offering, borrowings under our revolving credit facility and the sale of non-core oil and gas properties. DeGolyer and MacNaughton projects that we will incur capital costs in excess of $2,467 million over the next five years to develop the proved undeveloped reserves in the Williston Basin covered by its December 31, 2014 reserve report. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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A significant increase in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities and borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional debt or equity securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such debt securities.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our estimated net proved reserves;
- the level of oil and natural gas we are able to produce from existing wells and new projected wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of low oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. 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 cash 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 development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our estimated net proved reserves, and could adversely affect our business, financial condition and results of operations.

If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. In addition, we assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. Based on specific market factors and circumstances at the time of prospective impairment reviews, 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 natural gas properties, which may result in a decrease in the amount available under our revolving credit facility. A write-down constitutes a non-cash charge to earnings. Recent declines in oil and natural gas prices may cause us to incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our revolving credit facility and our results of operations for the periods in which such charges are taken. Due to lower expected future oil prices, we reviewed our proved oil and natural gas properties as of December 31, 2014 and determined that the carrying value exceeded expected undiscounted cash flows for certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations. As a result, we recorded an impairment loss of $40.0 million to adjust the carrying amount of these assets to fair value. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2013 and 2012. During the years ended December 31, 2014, 2013 and 2012, we recorded non-cash impairment charges of $7.3 million, $1.2 million and $3.6 million on our unproved properties due to expiring leases and periodic assessments of our unproved properties not held-by-production.

We will not be the operator on all of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We may enter into arrangements with respect to existing or future drilling locations that result in a greater proportion of our locations being operated by others. As a result, we may have limited ability to exercise influence over the operations of the drilling locations operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

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- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of our drilling locations may cause a material adverse effect on our results of operations and financial condition.

All of our producing properties and operations are located in the Williston Basin region, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2014, 100% of our proved reserves and production were located in the Williston Basin in northwestern North Dakota and northeastern Montana. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Williston Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our business depends on oil and natural gas gathering and transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. See also "Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production" and "Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices." We generally do not purchase firm transportation on third party pipeline facilities, and therefore, the transportation of our production can be interrupted by other customers that have firm arrangements. In addition, these third parties may also impose specifications for the products that they are willing to accept. If the total mix of a product fails to meet the applicable product quality specifications, the third parties may refuse to accept all or a part of the products or may invoice us for the costs to handle or damages from receiving the out-of-specification products. In those circumstances, we may be required to delay the delivery of or find alternative markets for that product, or shut-in the producing wells that are causing the products to be out of specification, potentially reducing our revenues.

The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored. A total shut-in of our production could materially affect us due to a resulting lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow. Potential crude oil rail derailments or crashes could also impact our ability to market and deliver our products and cause significant fluctuations in our realized oil and natural gas prices due to tighter safety regulations imposed on crude-by-rail transportation and interruptions in service.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. Although additional Williston Basin transportation takeaway capacity was added from 2011 to 2014, production also increased due to the elevated drilling activity in

these years. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in the first half of 2012. During the second half of 2012 and first half of 2013, differentials improved due to expanding rail infrastructure and pipeline expansions coming on line. During the second half of 2013 and first quarter of 2014, our price differentials again increased as the pipeline

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market weakened as a result of refinery down time and increased United States and Canadian production. In the second and third quarters of 2014, stronger pipeline prices shifted more of our barrels towards the pipelines, but rail buyers had to compete with pipeline prices despite weaker Brent differentials, and our price differentials to WTI returned to approximately 9% to 11%. In the fourth quarter of 2014, as WTI crude oil prices declined, our price differentials increased as a percentage of WTI but remained relatively flat in terms of the dollar per barrel discount to WTI in the range of $9.00 to $10.50 per barrel of oil. On barrels that are transported over pipelines to either Clearbrook, Minnesota or Guernsey, Wyoming, our realized price for crude oil is generally the quoted price for Bakken crude oil less transportation costs from the point where the crude oil is sold.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 46% of our estimated net proved reserves were classified as proved undeveloped as of December 31, 2014. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our revolving credit facility and derivative contracts. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our estimated net 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 flows 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 at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

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:

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environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gas or other pollutants into the environment;

- abnormally pressured formations;
- shortages of, or delays in, obtaining water for hydraulic fracturing activities;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing failure;

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- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We have incurred losses in prior years and may do so again in the future.

For the years ended December 31, 2014, 2013 and 2012, we had net income of $506.9 million, $228.0 million and $153.4 million, respectively. However, prior to 2011, we incurred net losses. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2015 of approximately $705 million.

The uncertainty and risks described in this Annual Report on Form 10-K may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

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

Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Williston Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. 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 natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of

the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2014, we had leases representing 24,697 net acres expiring in 2015, 18,235 net acres expiring in 2016 and 12,819 net acres expiring in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. During the years ended December 31, 2014, 2013 and 2012, we recorded non-cash impairment charges of $7.3 million, $1.2 million and $3.6 million on our unproved properties due to expiring leases and periodic assessments of our unproved properties not held-by-production.

Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling, underground injection or other regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, 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. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of well drilling, construction, completion on water management activities or operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. For example, the North Dakota Industrial Commission adopted regulations in late 2013 that impose more rigorous pipeline development standards on midstream operators, some of whom we rely upon to construct and operate pipeline infrastructure to transport the oil and natural gas we produce. In addition, in March 2014, the North Dakota Industrial Commission adopted legal requirements that went into effect on May 1, 2014 and implemented a drilling permit review process that incorporates public review measures for any oil and natural gas wells drilled within buffer zones established around a designated number of identified areas of interest within the state, including certain

National Park or Grassland areas, specified mountains and buttes, certain rivers, and specified wildlife management areas. While limited to drilling of wells upon public lands, the drilling permit review process will result in portions of the drilling applications being made available for public review and comment and could result in a lesser number of such permits being issued or such permits being issued as a slower rate or with added restrictions, which could impact our overall drilling program. We may not be able to recover some or any of these costs from insurance.

Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties.

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Our operations are substantially affected by federal, state and local laws and regulations, particularly as they relate to the regulation of oil and natural gas production and transportation. These laws and regulations include regulation of oil and natural gas exploration and production and related operations, including a variety of activities related to the drilling of wells, the interstate transportation of oil and natural gas by federal agencies such as the FERC, as well as state agencies. In addition, federal laws prohibit market manipulation in connection with the purchase or sale of oil and/or natural gas. Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties. Please see "Other federal laws and regulations affecting our industry."

Our business involves the selling and shipping by rail of crude oil, including from the Bakken shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our crude oil production is transported to market centers by rail. Recent derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable materials. Transportation safety regulators in the United States and Canada are concerned that crude oil from the Bakken shale may be more flammable than crude oil from other producing regions and are investigating that issue and are also considering changes to existing regulations to address those possible risks. The August 2014 Notice of Proposed Rulemaking published by PHMSA proposes, among other things, enhanced tank car standards, a classification and testing program for crude oil, and a phase-out date by as early as October 2017 for older DOT-111 tank cars that are not retrofitted. The proposed rule also includes new operational requirements such as route analyses, improved braking controls, and speed restrictions. In conjunction with the proposed rule, PHMSA published an Advanced Notice of Proposed Rulemaking related to potential revisions to its regulations that would expand the applicability of comprehensive oil spill response plans to certain trains based on the thresholds of crude oil that apply to an entire train. The final rule is expected in early 2015. Transport Canada has also issued emergency directives and ministerial orders relating to train speed restrictions, route risk analyses and a phase out of non-compliant DOT-111 tank cars.

Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

To the extent that new regulations require design changes or other modifications of tank cars, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our policies will cover the entirety of any damages that may arise from such an event.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Based on findings by the EPA in 2009 that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth's atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the CAA that establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. These or similar permit review requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas production facilities on an annual basis, which includes certain of our operations.

While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose

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additional direct costs on operations and reduce demand for refined products. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas facilities, including production facilities, as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the federal BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. In addition, from time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. In addition, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional drilling locations 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 for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may

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be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. 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, which could have a material adverse effect on our business.

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

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 Thomas B. Nusz, our Chairman and Chief Executive Officer, and Taylor L. Reid, our President and Chief Operating Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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

Oil and natural gas operations in the Williston Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months. Severe winter weather conditions limit and may temporarily halt our ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the negative effect of commodity price changes, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the U.S. District Court for the District of Columbia in September of 2012, although the CFTC has stated that it will appeal the District Court’s decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of “swap,” “security-based swap,” “swap dealer” and “major swap participant.” The Dodd-Frank Act and CFTC Rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has

delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could

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significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our senior unsecured notes. If amounts outstanding under our revolving credit facility or our senior unsecured notes were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and capital resources.”

Our revolving credit facility and the indentures governing our senior unsecured notes all contain operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility and the indentures governing our senior unsecured notes contain a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;

- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;

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- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indentures governing our senior unsecured notes may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or continue to decline, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, the indentures governing our senior unsecured notes or any future indebtedness could result in an event of default under our revolving credit facility, the indentures governing our senior unsecured notes or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under the indentures for our senior unsecured notes. If the indebtedness under the notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and capital resources.”

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2014, we had $500.0 million of outstanding borrowings and had $5.2 million of outstanding letters of credit under our revolving credit facility, $994.8 million available for future secured borrowings under our revolving credit facility and $2,200.0 million outstanding in senior unsecured notes. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and capital resources–Senior secured revolving line of credit” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and capital resources–Senior unsecured notes.” In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

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- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, and borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($130.9 million in receivables at December 31, 2014), which we market to energy marketing companies, refineries and affiliates, and joint interest receivables ($175.5 million at December 31, 2014).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the years ended December 31, 2014, 2013 and 2012, sales to Musket Corporation accounted for approximately 13%, 11% and 10% of our total sales, respectively. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2014, 2013 and 2012. We do not require all of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Derivative assets and liabilities arising from derivative contracts with the same counterparty are reported on a net basis, as all counterparty contracts provide for net settlement. At December 31, 2014, we had derivatives in place with seven counterparties and a total net derivative asset of $315.5 million.

We may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
-

validity of the seller’s title to the properties, which may be less than expected at the time of signing the purchase agreement; and

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- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities or title defects in excess of the amounts claimed by us before closing and acquire properties on an "as is" basis. Indemnification from the sellers will generally be effective only during the twelve-month period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with the sellers or their inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated net proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, in oil and natural gas industry conditions, by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in the title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

President Obama's budget proposal for fiscal year 2016 recommended the elimination of certain key United States federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities for oil and gas production, and (iv) the extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes or similar changes will be enacted or, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders' only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the indentures governing our senior unsecured notes. Consequently, our shareholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified Board of Directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board of Directors.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding other than those noted below. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

On July 6, 2013, a freight train operated by Montreal, Maine and Atlantic Railway (“MMA”) carrying crude oil (the “Train”) derailed in Lac-Mégantic, Quebec. In March 2014, Oasis Petroleum Inc. and OP LLC were added to a group of over fifty named defendants, including other crude oil producers as well as the Canadian Pacific Railway, MMA and certain of its

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affiliates, owners and transloaders of the crude oil carried by the Train, several lessors of tank cars, and the Attorney General of Canada, in a motion filed in Quebec Superior Court to authorize a class-action lawsuit seeking economic, compensatory and punitive damages, as well as costs for claims arising out of the derailment of the Train (Yannick Gagne, etc., et al. v. Rail World, Inc., etc., et al., Case No. 48006000001132). The motion generally alleges wrongful death and negligence in the failure to provide for the proper and safe transportation of crude oil.
We believe that all claims against Oasis Petroleum Inc. and OP LLC in connection with the derailment of the Train in Lac-Mégantic, Quebec are without merit and intend to vigorously defend against them.

Item 4. Mine Safety Disclosures
Not applicable.

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PART II

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

Market for Registrant's Common Equity. Our common stock is listed on the NYSE under the symbol "OAS."

The following table sets forth the range of high and low sales prices of our common stock for the two most recent fiscal years as reported by the NYSE:

	2014		2013	
	High	Low	High	Low
1st Quarter	$47.28	$38.68	$39.78	$31.45
2nd Quarter	$56.38	$41.01	$42.89	$31.58
3rd Quarter	$58.09	$40.85	$49.48	$37.86
4th Quarter	$41.90	$10.64	$57.33	$42.70

Holders. The number of shareholders of record of our common stock was approximately 65,612 on February 20, 2015.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility and the indentures governing our senior unsecured notes restrict the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On February 25, 2015, the last sale price of our common stock, as reported on the NYSE, was $15.73 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2014.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2014:

Period	Total Number of Shares Exchanged[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
October 1 – October 31, 2014	1,127	$40.03	—	—
November 1 – November 30, 2014	649	29.96	—	—
December 1 – December 31, 2014	652	15.89	—	—
Total	2,428	$30.85	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of our common stock.

Stock Performance Graph. The following performance graph and related information is "furnished" with the SEC and shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph shown below compares the cumulative total return to the Company's common stockholders as compared to the cumulative total returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P 500 O&G E&P") since the time of our IPO. The comparison was

prepared based upon the following assumptions:

1. $100 was invested in our common stock at its IPO price of $14 per share and invested in the S&P 500 and the S&P 500 O&G E&P on June 16, 2010 at the closing price on such date; and

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2. Dividends were reinvested.

Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, and balance sheet data at December 31, 2014, 2013, 2012, 2011 and 2010. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

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	Year ended December 31,				
	2014	2013[1]	2012	2011	2010
	(In thousands, except per share data)				
Statement of operations data:					
Revenues:					
Oil and gas revenues	$1,304,004	$1,084,412	$670,491	$330,422	$128,927
Well services and midstream revenues	86,224	57,587	16,177	—	—
Total revenues	1,390,228	1,141,999	686,668	330,422	128,927
Expenses:					
Lease operating expenses[2]	169,600	94,634	54,924	32,707	14,118
Well services and midstream operating expenses	50,252	30,713	11,774	—	—
Marketing, transportation and gathering expenses	29,133	25,924	9,257	1,365	464
Production taxes	127,648	100,537	62,965	33,865	13,768
Depreciation, depletion and amortization	412,334	307,055	206,734		