Oasis Petroleum Inc.
Form 10-K
February 23, 2017
Table of Contents

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, 2016
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: $1,684,927,220

Number of shares of registrant’s common stock outstanding as of February 17, 2017: 237,484,249

Documents Incorporated By Reference:

Portions of the registrant’s definitive proxy statement for its 2017 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2016, are incorporated by reference into Part III of this report for the year ended December 31, 2016.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2016
TABLE OF CONTENTS

Table of Contents

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 (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “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,” “ “potential,” “project” and 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 a midstream company;
- owning and operating a well services company;
- infrastructure for salt water gathering and disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Williston Basin;
- 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.

PART I

Item 1. Business

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the "Company," "we," "us," or "our") was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. We are 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. Oasis Petroleum North America LLC ("OPNA") conducts our exploration and production activities and owns our proved and unproved oil and natural gas properties. We also operate a midstream services business through Oasis Midstream Services LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS").

As of December 31, 2016, we have accumulated 517,801 net leasehold acres in the Williston Basin, of which approximately 94% 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 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 2016, we completed and placed on production 57 gross operated wells in the Williston Basin and had average daily production of 50,372 Boe per day. As of December 31, 2016, we had 1,413 gross (756.5 net) producing wells in the Bakken and Three Forks formations. DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 305.1 MMBoe as of December 31, 2016, of which 62% were classified as proved developed and 78% were oil.

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 are developing our acreage position to maximize the value of our resource potential, while maintaining flexibility to preserve future value when oil prices are low. During 2016, when the NYMEX West Texas Intermediate crude oil index price ("WTI") averaged $43.40 per barrel for the year, we completed and brought on production 57 gross (37.6 net) operated Bakken and Three Forks wells. As of December 31, 2016, we had 83 gross operated wells waiting on completion in the Bakken and Three Forks formations. Our 2017 capital plan contemplates completing and placing on production approximately 76 gross (51.7 net) operated wells. We have the ability to increase or decrease the number of wells drilled and the number of wells completed during 2017 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 operating cost-efficient development programs. We believe the magnitude and concentration of our acreage within the Williston Basin, particularly in the core of the play, 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, utilize centralized production and oil, gas and water fluid handling facilities and infrastructure, and reduce the time and cost of rig mobilization. In addition, we expect OMS and OWS to continue to provide operational synergies 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 have continued to reduce the number of days that it takes to drill wells, and we believe completion techniques have significantly evolved over the past decade, resulting in increased initial production rates and recoverable hydrocarbons per well. High intensity completion techniques continue to deliver production performance greater than prior completion techniques. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This ongoing 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. We have no short-term debt maturities, and as of December 31, 2016, we had $785.9 million of liquidity available, including $11.2 million of cash and cash equivalents and $774.7 million of unused borrowing base capacity available under our revolving credit facility. Our liquidity position, along with internally generated cash flows from operations, will provide continued financial flexibility as we actively manage the pace of development on our acreage position in the Williston Basin. We currently believe we have access to the public and private capital markets, and we intend to maintain a

Table of Contents

balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise. We also continue to evaluate 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. In 2016, we acquired approximately 55,000 net acres in the Williston Basin. 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. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations. As of December 31, 2016, substantially all of our 517,801 net leasehold acres in the Williston Basin were highly prospective in the Bakken and Three Forks formations, and 78% of our 305.1 MMBoe estimated net proved reserves in this area were comprised of oil. In addition, we have 484,321 net acres held by production as of December 31, 2016. In 2016, we increased per well capital efficiency through our focused development efforts in our core acreage and improved operational efficiency, coupled with lower service costs from third-party vendors, OMS and OWS. In 2017, we will continue to concentrate our drilling and completion activities in our core acreage.
- 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 complete 76 gross (51.7 net) operated wells in the Williston Basin in 2017.
- Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry with 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 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. In 2016, an average of 45% of our executive officers' overall compensation was in long-term equity-based incentive awards, and such officers owned over 3.6 million shares of our outstanding common stock as of December 31, 2016. 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, 2016, 95% of our estimated net proved reserves were attributable to properties that we expect to operate, and our average working interest in our 2017 operated completion plan is expected to be 68%. Approximately 95% of our 2017 drilling and completion capital expenditure budget is related to operated wells. 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.
- Vertical integration. Our investments in and operational control of OMS and OWS provide us with additional operational efficiencies and cost savings compared to our peers. This vertical integration helps us control capital dollars being spent in advance of production to ensure volumes flow, improve uptime performance of our producing wells, protect against rising service costs, increase transparency in the planning process and increase communications with vendors by purchasing directly from them.

Table of Contents

Our operations

Proved reserves

Our estimated net proved reserves and related PV-10 at December 31, 2016, 2015 and 2014 are 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, 2016, 2015 and 2014 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 index prices for oil and natural gas, which 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 $42.60 per Bbl for oil and $2.47 per MMBtu for natural gas, $50.16 per Bbl for oil and $2.63 per MMBtu for natural gas and $95.28 per Bbl for oil and $4.35 per MMBtu for natural gas for the years ended December 31, 2016, 2015 and 2014, 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. 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. Future net revenues represent projected revenues from the sale of our estimated net proved reserves (excluding derivative contracts) net of production and development costs (including operating expenses and production taxes). PV-10 and Standardized Measure represent the present value of the future net revenues discounted at 10%, before and after income taxes, respectively.

There are numerous uncertainties inherent in estimating reserves and related information, and different reservoir engineers often arrive at different estimates for the same properties. There can be no assurance that our estimated net proved reserves will be produced within the periods indicated or that prices and costs will remain constant. 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.

The following table summarizes our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure:

	At December 31,		
	2016	2015	2014
Estimated proved reserves:			
Oil (MMBbls)	236.6	184.9	235.4
Natural gas (Bcf)	411.1	199.8	220.1
Total estimated proved reserves (MMBoe)	305.1	218.2	272.1
Percent oil	78 %	85 %	87 %
Estimated proved developed reserves:			
Oil (MMBbls)	152.3	127.4	127.3
Natural gas (Bcf)	229.6	120.8	114.0
Total estimated proved developed reserves (MMBoe)	190.6	147.6	146.3
Percent proved developed	62 %	68 %	54 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	84.3	57.5	108.1
Natural gas (Bcf)	181.5	79.0	106.1
Total estimated proved undeveloped reserves (MMBoe)	114.5	70.7	125.7
Future net revenues (in millions)	$4,645.6	$3,827.9	$11,999.3
PV-10 (in millions)(1)	$2,627.8	$2,022.7	$5,481.4
Standardized Measure (in millions)(2)	$2,483.1	$1,914.3	$3,981.7

(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 reserves. 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) 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.

Estimated net proved reserves at December 31, 2016 were 305.1 MMBoe, a 40% increase from estimated net proved reserves of 218.2 MMBoe at December 31, 2015 primarily due to acquisitions and revisions related to larger completion designs, partially offset by lower commodity prices and the 2016 divestiture of certain legacy wells that were 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. Our proved developed reserves increased 43.0 MMBoe, or 29%, to 190.6 MMBoe for the year ended December 31, 2016 from 147.6 MMBoe for the year ended December 31, 2015, primarily due to acquisitions and our 2016 drilling program, including the completion of 57 gross (37.6 net) operated wells, partially offset by production and higher abandonment rates resulting from lower commodity price assumptions. Our proved undeveloped reserves increased to 114.5 MMBoe for the year ended December 31, 2016 from 70.7 MMBoe for the year ended December 31, 2015 due to acquisitions and positive revisions related to larger completion designs, partially offset by conversions of wells to proved developed as a result of our 2016 drilling program and the removal of proved undeveloped reserves that are no longer aligned with our anticipated five-year drilling plan as of December 31, 2016.

Estimated net proved reserves at December 31, 2015 were 218.2 MMBoe, a 20% decrease from estimated net proved reserves of 272.1 MMBoe at December 31, 2014 primarily due to revisions related to lower commodity prices, partially offset by our 2015 drilling program and well completions as well as lower estimated future operating and capital costs. Our proved developed reserves increased 1.3 MMBoe, or 1%, to 147.6 MMBoe for the year ended December 31, 2015 from 146.3 MMBoe for the year ended December 31, 2014, primarily due to our 2015 drilling program, including the completion of 80 gross (62.4 net) operated wells, partially offset by production and higher abandonment rates resulting from lower commodity price assumptions. Our proved undeveloped reserves decreased to 70.7 MMBoe for the year ended December 31, 2015 from 125.7 MMBoe for the year ended December 31, 2014 due to increases from our 2015 drilling program offset by the removal of proved undeveloped reserves that were not economic at the lower oil price or were no longer aligned with our anticipated five-year drilling plan as of December 31, 2015.

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%. 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,		
	2016	2015	2014
		(In millions)	

PV-10	$2,627.8	$ 2,022.7	$5,481.4
Present value of future income taxes discounted at 10%	144.7	108.4	1,499.7
Standardized Measure of discounted future net cash flows	$2,483.1	$ 1,914.3	$3,981.7

The PV-10 of our estimated net proved reserves at December 31, 2016 was $2,627.8 million, a 30% increase from PV-10 of $2,022.7 million at December 31, 2015. This increase was primarily due to an increase in reserves and a reduction in future development costs, partially offset by lower commodity price assumptions year over year.

Table of Contents

Proved undeveloped reserves

At December 31, 2016, we had approximately 114.5 MMBoe of proved undeveloped reserves as compared to 70.7 MMBoe at December 31, 2015.

The following table summarizes the changes in our proved undeveloped reserves during 2016:

	Year Ended December 31, 2016 (in MBoe)
Proved undeveloped reserves, beginning of period	70,656
Extensions, discoveries and other additions	6,493
Purchases of minerals in place	33,449
Sales of minerals in place	(4,603)
Revisions of previous estimates	30,030
Conversion to proved developed reserves	(21,513)
Proved undeveloped reserves, end of period	114,512

During 2016, we spent a total of $155.1 million related to the development of proved undeveloped reserves, $39.5 million of which was spent on proved undeveloped reserves that represent wells in progress at year-end. The remaining $115.6 million resulted in the conversion of 21,513 MBoe of proved undeveloped reserves, or 30% of our proved undeveloped reserves balance at the beginning of 2016, to proved developed reserves. We added 6,493 MBoe of proved undeveloped reserves in the Williston Basin as a result of our 2016 operated and non-operated drilling program and anticipated five-year drilling plan. We participated in 64 gross (38.1 net) wells that were completed and brought on production during 2016. In addition, we purchased 33,449 MBoe of proved undeveloped reserves as a result of acquisitions and traded acreage during the year ended December 31, 2016. As a result of traded acreage in 2016, we divested 4,603 MBoe of proved undeveloped reserves. In 2016, our net positive revision of 30,030 MBoe, or 43% of our December 31, 2015 proved undeveloped reserves balance, is primarily due to larger completion designs and a higher gas to oil ratio, partially offset by the removal of proved undeveloped reserves, including 28 gross (20.2 net) proved undeveloped locations with 9,455 MBoe of reserves that are no longer aligned with our anticipated five-year drilling plan and lower commodity prices.

We expect to develop all of our proved undeveloped reserves as of December 31, 2016 within five years after the initial year booked. 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 or continuous drilling operations. Approximately 33% of our proved undeveloped reserves at December 31, 2016 are attributable to wells that have been drilled but not yet completed, and 100% of our undrilled reserves are within our core acreage in the Williston Basin.

Reserves sensitivity

Our estimated net proved reserves at December 31, 2016 were prepared using SEC pricing for crude oil of $42.60 per barrel and natural gas of $2.47 per MMBtu. Based on low commodity prices in recent years and expected continued commodity price volatility, the following sensitivity table is provided to illustrate the potential impact on our estimated net proved reserves, PV-10 and Standardized Measure if the commodity prices were to decrease to levels in line with the first quarter of 2016, which were the lowest quarterly average commodity prices during the recent downturn. Management cannot predict future commodity prices and is not currently forecasting such a decrease in prices, but based on market volatility, the uncertainty of price assumptions and historical precedence, management believes it is reasonably possible that these prices could occur again in the future. The reduction in net proved reserves in the sensitivity case provided is attributable to reaching the economic limit sooner as a result of the decreased prices.

Table of Contents

	Actual at December 31, 2016		Sensitivity Case	
Oil price (per Bbl)[1]	$	42.60	$	35.00
Natural gas price (per MMBtu)[1]	2.47		2.00	
Estimated proved developed reserves (MMBoe)	190.6		175.8	
Estimated proved undeveloped reserves (MMBoe)	114.5		111.5	
Total estimated proved reserves (MMBoe)	305.1		287.3	
PV-10 (in millions)	$	2,627.8	$	1,784.9
Present value of future income taxes discounted at 10% (in millions)	144.7		—	
Standardized Measure of discounted future net cash flows (in millions)	$	2,483.1	$	1,784.9

(1) Our estimated net proved reserves, PV-10 and Standardized Measure were determined using prices for oil and natural gas, without giving effect to derivative transactions, which were held constant throughout the life of the properties. The 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 actual reserve estimates at December 31, 2016 were prepared using SEC pricing, calculated as the unweighted arithmetic average first-day-of-the-month prices for the prior twelve months, which was $42.60 per Bbl for oil and $2.47 per MMBtu for natural gas for the year ended December 31, 2016. The price for the sensitivity case is in line with historical lows experienced during the first quarter of 2016.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues and PV-10 at December 31, 2016, 2015 and 2014 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 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.

Table of Contents

Estimates of reserves were prepared 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). The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by us to DeGolyer and MacNaughton and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production decline curves, reserves were estimated only to the limits of economic production.

Undeveloped reserves were estimated for locations adjacent to existing wells and are based on consideration of lateral length, completion and production profiles compared by appropriate target reservoir. In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data was available.

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 over 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;
- 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 grew dramatically over the past several years, and this contributed to a global oversupply of crude oil, which caused a sharp decline in oil prices beginning in mid-2014. In 2015 and 2016, oil inventories continued to build as global oil supply continued to outpace demand. On November 30, 2016, members of the Organization of Petroleum Exporting Countries (“OPEC”) agreed to reduce oil production in the first half of 2017, and in December 2016, non-OPEC countries, including Russia, also agreed to reduce output in early 2017 as part of an effort with

10

Table of Contents

OPEC countries to accelerate rebalancing the oil market. These agreements contributed to the increase in oil prices at the end of 2016. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. Further declines in oil and natural gas prices, extended low oil and 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—Further declines, or extended low commodity prices, 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,		
	2016	2015	2014
Net production volumes:			
Oil (MBbls)	15,174	16,091	14,883
Natural gas (MMcf)	19,573	14,002	10,691
Oil equivalents (MBoe)	18,436	18,424	16,664
Average daily production (Boe per day)	50,372	50,477	45,656
Average sales prices:			
Oil, without derivative settlements (per Bbl)(1)	$ 38.64	$ 43.04	$ 82.73
Oil, with derivative settlements (per Bbl)(1)(2)	46.68	66.06	83.19
Natural gas (per Mcf)(3)	1.99	2.08	6.81
Costs and expenses (per Boe of production):			
Lease operating expenses	$ 7.35	$ 7.84	$ 10.18
Marketing, transportation and gathering expenses	2.19	1.72	1.75
Production taxes	3.07	3.78	7.66
Depreciation, depletion and amortization	25.84	26.34	24.74
General and administrative expenses	5.04	5.02	5.54

---

(1) For the year ended December 31, 2016, average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales of $10.3 million, divided by oil production.

(2) 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.

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

Net production volumes for the year ended December 31, 2016 were 18,436 MBoe as compared to net production of 18,424 MBoe for the year ended December 31, 2015. Our net production volumes remained relatively consistent from 2015 to 2016 primarily due to a successful operated and non-operated drilling and completion program and our recent acquisition of producing properties in December 2016, offset by the natural decline in production in wells that were producing as of December 31, 2015. Average oil sales prices, without derivative settlements, decreased by $4.40 per barrel, or 10%, to an average of $38.64 per barrel for the year ended December 31, 2016 as compared to the year ended December 31, 2015. Giving effect to our derivative transactions in both periods, our oil sales prices decreased $19.38 per barrel to $46.68 per barrel for the year ended December 31, 2016 from $66.06 per barrel for the year ended December 31, 2015.

Net production volumes for the year ended December 31, 2015 were 18,424 MBoe, an 11% increase from net production of 16,664 MBoe for the year ended December 31, 2014. Our net production volumes increased 1,760 MBoe over 2014 primarily due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without derivative settlements, decreased by $39.69 per barrel, or 48%, to an average of $43.04 per barrel for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Giving effect to our derivative transactions in both periods, our oil sales prices decreased $17.13 per barrel to $66.06 per barrel for the year ended December 31, 2015 from $83.19 per barrel for the year ended December 31, 2014.

Table of Contents

Productive wells

The following table presents the total and operated gross and net productive wells as of December 31, 2016:

	Total wells		Operated wells	
	Gross	Net	Gross	Net
Bakken and Three Forks	1,413	756.5	909	693.3
Other	84	54.5	66	51.8
Total wells	1,497	811.0	975	745.1

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, 2016. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Gross	Net
Developed acres	558,564	417,220
Undeveloped acres	171,703	100,581
Total acres	730,267	517,801

We increased our acreage that is held by production to 484,321 net acres at December 31, 2016 from 442,292 net acres at December 31, 2015 primarily due to our acquisitions during 2016.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2016 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates:

	Undeveloped acres expiring	
	Gross	Net
Year ending December 31,		
2017	13,935	9,970
2018	12,252	8,864
2019	3,054	2,923

Drilling and completion activity

The following table summarizes our completion activity for the years ended December 31, 2016, 2015 and 2014. Gross wells reflect the sum of all productive and dry wells, operated and non-operated, in which we own a working 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.

Table of Contents

	Year ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	64	38.1	115	59.1	188	102.6
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	64	38.1	115	59.1	188	102.6
Exploratory wells:						
Oil	—	—	6	5.2	81	48.5
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	—	—	6	5.2	81	48.5
Total wells	64	38.1	121	64.3	269	151.1

Since 2014, we have focused on full field development and have concentrated on improving capital efficiency and completing more wells using high-intensity completion techniques in 2015 and 2016. We also continued to participate in a number of wells on a non-operated basis.

We did not drill any dry hole wells in 2016, 2015 or 2014.

As of December 31, 2016, we had two operated rigs running, 2 gross (1.3 net) operated wells drilling and an inventory of 83 gross operated wells waiting on completion. We expect to continue to concentrate drilling activities in the Bakken and Three Forks formations within our core acreage in 2017.

Capital expenditure budget

In 2016, we spent $1,181.5 million on capital expenditures, which represented a 94% increase over the $610.0 million spent during 2015. Excluding acquisitions of $781.5 million in 2016 and $28.7 million in 2015, our capital expenditures decreased 31% to $400.0 million from the $581.3 million spent during 2015. This reduction was primarily due to reduced drilling and completion activity as a result of lower commodity prices in 2016 coupled with lower well costs as a result of both improved operational efficiency and lower service costs, partially offset by higher capital expenditures for OMS, primarily related to the construction of midstream infrastructure, including a natural gas processing plant and crude oil system, in our Wild Basin area in North Dakota. 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 increased our planned 2017 capital expenditures as compared to 2016, excluding acquisitions, as a result of current commodity prices. Our total 2017 capital expenditure budget is $605 million, which includes $410 million of drilling and completion capital expenditures (including expected savings from services provided by OWS and OMS), $110 million for midstream infrastructure and $85 million of other capital expenditures, including other E&P capital, capitalized interest, well services equipment and administrative capital. We plan to complete approximately 76 gross (51.7 net) operated wells and participate in 2.4 net non-operated wells that are expected to be completed and brought on production in 2017.

While we have budgeted $605 million in 2017 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.”

Description of properties

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 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 generally 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,

Table of Contents

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 has been one of the most actively drilled unconventional oil resource plays in the United States, reaching over 200 rigs drilling in the basin in 2014. The active rig count decreased throughout 2015 and 2016 due to low oil prices and fell to fewer than 25 rigs drilling in the basin in the second quarter of 2016. In the second half of 2016, the active rig count slightly increased to over 30 rigs currently drilling. Most rigs that are running in the Williston Basin are focused on drilling areas with the highest estimated ultimate recoveries that have attractive economics even in depressed oil price environments. Our development activity is focused in the deepest part of the Williston Basin, which we call the core.

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. 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, 2016 consisted of 517,801 net acres. Our estimated net proved reserves in the Williston Basin were 305.1 MMBoe at December 31, 2016. Of our estimated net proved reserves in the Williston Basin, approximately 190.6 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, 114.5 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three Forks wells to be drilled with more recent completion techniques, which incorporates the impact of high intensity completion techniques. As of December 31, 2016, we had a total of 811.0 net operated and non-operated producing wells and 745.1 net operated producing wells in the Williston Basin. We had average daily production of 50,372 net Boe per day for the year ended December 31, 2016 in the Williston Basin. During 2016, our Bakken and Three Forks wells produced a daily average of 50,131 net Boe per day with 756.5 net producing wells on December 31, 2016. Accordingly, our 756.5 net Bakken and Three Forks wells were responsible for nearly 100% of our average daily production during 2016. As of December 31, 2016, our working interest for all producing wells averaged 54% and in the wells we operate averaged 76%. As of December 31, 2016, we had 141 gross (65.2 net) wells in the process of being drilled or completed in the Williston Basin, which includes two gross operated wells drilling, 83 gross operated wells waiting on completion and 56 gross non-operated wells drilling or completing. We participated in 64 gross (38.1 net) wells that were completed and brought on production during 2016.

Marketing, transportation and major customers

The Williston Basin crude oil rail and pipeline transportation and refining infrastructure has grown substantially over the past decade, largely in response to drilling activity in the Bakken and Three Forks formations. In December 2016, oil production in North Dakota was approximately 942,000 barrels per day. According to the North Dakota Pipeline Authority website’s data last updated January 13, 2017, there was approximately 851,000 barrels per day of crude oil pipeline transportation capacity and approximately 1,520,000 barrels per day of specifically dedicated rail loading capacity in the Williston Basin as of December 31, 2016. In 2016, we continued to sell a significant amount of our crude oil production 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, 2016, we were flowing over 90% of our gross operated oil production through these gathering systems.

Crude oil produced and sold in the Williston Basin has historically sold at a discount to WTI 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. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually

Table of Contents

declined. Since the third quarter of 2015, our price differentials have averaged less than $5.00 per barrel discount to WTI. We expect differentials to improve as takeaway capacity in the Williston Basin will increase by over 500,000 barrels of oil per day if the Dakota Access Pipeline is completed and put in service. 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. 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."

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 "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." At the end of 2015, the U.S. government lifted the long-standing ban on crude oil exports. While we believe this could have a positive impact on the long-term value of Bakken crude oil, current market conditions are not expected to result in sizable quantities of U.S. crude oil being exported out of the country.

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. As of December 31, 2016, we sold a substantial majority of our oil and condensate through bulk sales at 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. We also entered into various short-term sales contracts for a portion of our portfolio at fixed differentials. 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 year ended December 31, 2016, sales to PBF Holding Company LLC accounted for approximately 10% of our total sales. For the year ended December 31, 2015, sales to Shell Trading (US) Company accounted for approximately 10% of our total sales. For the year ended December 31, 2014, sales to Musket Corporation accounted for approximately 13% of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2016, 2015 and 2014. 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 the Williston Basin.

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, worldwide and regional economic conditions, global and domestic oil supply, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of 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—Further declines, or extended low commodity prices, 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 estimated 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 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."

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.”

Competition

The oil and natural gas industry is worldwide and 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, completion 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 producing, midstream and well services operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production, oil gathering and transportation, natural gas processing 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 or otherwise provide midstream services have statutory provisions regulating the exploration for and production of oil and natural gas or the gathering, transportation and processing of those commodities, including provisions related to permits for the drilling of wells or processing of natural gas, bonding requirements to drill or operate producing or injection wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled or processing plants are constructed, 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, the siting of processing plants, disposal wells and gathering or transportation lines, 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. Historically, our compliance costs with applicable laws and regulations have not had a material adverse effect on our financial position, cash flow and results of operations; however, there can be no assurance that such costs will not be material in the future as these laws and regulations are subject to amendment or reinterpretation. Additionally, currently unforeseen environmental incidents such as spills or other releases 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 Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Table of Contents

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 derailments of freight trains have led transportation safety regulators in the United States and Canada 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 crude oil on the shipping documentation do not in all cases accurately capture the flammability of the Bakken shale crude oil. In January 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 ("FRA") had launched an enforcement initiative that involved 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 this enforcement initiative from August 2013 to May 2014, Bakken shale crude oil tended to be more volatile and flammable than other crude oils, and thus posed an increased risk for a significant accident.

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, including ethanol, have been built to more stringent safety standards. In May 2015, PHMSA adopted a final rule that includes, among other things, additional requirements to 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 phased out by as early as October 1, 2017 if they are not already retrofitted to comply with new tank car design standards. The rule also includes a new braking standard for certain trains, designates new operational protocols for trains transporting large volumes of flammable liquids, such as routing analyses, speed restrictions and information for local government agencies, and provides new sampling and testing requirements to improve classification of energy products placed into transport. In August 2016, PHMSA released a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029. Additionally, in July 2016, PHMSA proposed a new rule that would expand the applicability of comprehensive oil spill response plans so that any railroad that transports a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train must have a current, comprehensive, written plan. In response to a petition from the New York Attorney General, PHMSA issued an advance notice of proposed rulemaking ("ANPR") in January 2017 stating that it is considering revising the Hazardous Materials Regulations ("HMR") to establish vapor pressure limits for unrefined petroleum-based products and potentially all Class 3 flammable liquid hazardous materials that would apply during the transportation of the products or materials by any mode. In addition, in February 2016, the FRA modified its accident and incident reports to gather additional data concerning rail cars carrying crude oil in any train involved in an FRA-reportable accident. In addition to action taken or proposed by federal agencies, a number of states proposed or enacted laws in recent years that encourage safer rail operations or urge the federal government to strengthen requirements for these operations.

Table of Contents

Safety improvements or updates to existing tank cars that are imposed under the May 2015 PHMSA requirements 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 these enhanced standards resulting from PHMSA's final rule will not increase our costs of doing business or 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.

Efforts are likewise underway in Canada to assess and address risks from the transport of crude oil by rail. For example, 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. At the same time that PHMSA released its 2015 rule, Canada's Minister of Transport announced Canada's new tank car standards, which largely align with the requirements in the PHMSA rule. Likewise, Transport Canada's rail car retrofitting and phase out timeline largely aligns with the timeline introduced under the 2015 and 2016 PHMSA rules. Transport Canada has also introduced new requirements that railways carry minimum levels of insurance depending on the quantity of crude oil or dangerous goods that they transport as well as a final report recommending additional practices for the transportation of dangerous goods.

Historically, our hazardous materials transportation compliance costs have not had a material adverse effect on our results of operations; however, these, and future laws, regulatory changes, or initiatives regarding hazardous material transportation, could directly and indirectly increase our operation, compliance and transportation costs and lead to shortages in availability of tank cars. We cannot assure that costs incurred to comply with standards and regulations emerging from these and future rulemakings will not be material to our business, financial condition or results of operations. Moreover, 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 insurance policies will cover the entirety of any damages that may arise from such an event. Nonetheless, 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 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, as described below. 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.

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 natural gas rules. The North Dakota Industrial Commission (“NDIC”) regulates the drilling and production of oil and natural gas in North Dakota. Beginning in 2012, the NDIC has adopted more stringent rule changes to its existing oil and natural gas regulations, imposing relatively higher bonding amounts for the drilling of wells, severely restricting the discharge and storage of production wastes such as produced water, drilling mud, waste oil and other wastes in earthen pits, implementing more stringent hydraulic fracturing requirements and requiring the provision of public disclosure on the national website, FracFocus.org, regarding chemicals used in the hydraulic fracturing process. During 2016, the NDIC approved a suite of additional rules for the conservation of crude oil and natural gas. New requirements relating to site construction, underground gathering pipelines and spill containment became effective on October 1, 2016 while other requirements relating to bonding requirements for underground gathering pipelines, and construction of berms around facilities became effective on January 1, 2017. Responding to these recent rule changes by oil and natural gas E&P operators in general, and us in particular, increased our well costs from 2012 to 2016, and we expect to continue to incur these increased costs as well as added costs with respect to the 2016 rule changes in order to respond to currently required requirements. Furthermore, in 2014, the NDIC adopted an order intended to reduce natural gas flaring, which order was subsequently modified in late 2015. Please see below the discussion of “Environmental protection and natural gas flaring initiatives” for more information on this order. In addition, on December 9, 2014, the NDIC adopted new conditioning standards to improve the safety of Bakken crude oil for transport. The rule became 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.

Pipeline safety regulation

Certain of our pipelines are subject to regulation by PHMSA under the Hazardous Liquids Pipeline Safety Act (“HLPSA”) with respect to oil and condensates and the Natural Gas Pipeline Safety Act (“NGPSA”) with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of oil and natural gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in high consequence areas (“HCAs”), such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas and hazardous liquid pipelines, which regulations may impose more stringent requirements than found under federal law. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance costs will not have a material adverse effect on

Table of Contents

our business and operating results. New laws or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays.

The HLPSA and NGPSA were amended by the Pipeline, Safety, Regulatory Certainty and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"), which became law in January 2012. The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. More recently, in June 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "2016 Pipeline Safety Act ") was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

The adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on our results of operations. For example, in April 2015, PHMSA proposed rulemaking that would require leak detection for all hazardous liquid pipelines, including those conveying oil, and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. New laws or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. In the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines.

Environmental and occupational health and safety regulation

Our exploration, development and production operations, oil gathering and transportation activities, natural gas processing services and related operations are subject to stringent 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 drilling, provide midstream services; 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, pits, processing plants and pipelines; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures, the occurrence of delays in the permitting or development or expansion of projects 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 results of operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental spills or other releases may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such spills or releases, including any third-party claims for damage to property, natural resources or persons. While, historically, our compliance costs with environmental laws and regulations have not had a material adverse effect on our financial position, cash flow and results of operations, there can be no assurance that such costs

Table of Contents

will not be material in the future as a result of such existing laws and regulations 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, as amended from time to time, 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 ("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 ("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. In the course of our operations, we generate ordinary industrial wastes that may be regulated as hazardous wastes. 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. For example, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and natural gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Repeal or modification of the current 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 or our customers to incur increased operating costs, which could have a significant impact on us as well as reduce demand for our midstream services.

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 or for conducting midstream services. 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 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, processing plant or pipeline closure operations to prevent future contamination.

Air emissions

The federal Clean Air Act ("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 October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards. State implementation of these revised standards could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Additionally, the EPA issued final CAA regulations in 2012 that include New Source Performance Standards ("NSPS") for completions of hydraulically fractured natural gas wells and issued added CAA regulations in June 2016 that include new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified and reconstructed equipment and processes in the oil and natural gas source category, including production activities. Compliance with this final rule or any other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, significantly increase our capital expenditures and operating costs, and reduce demand for the oil and natural gas that we produce, which one or more developments could adversely impact our business.

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 efforts 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, consistent with applicable requirements.

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 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, by having approximately 98% of our operated Bakken and Three Forks wells connected to gathering systems as of both December 31, 2016 and 2015. We believe that achieving this goal helps us to minimize our flared volumes of natural gas.

On July 1, 2014, the NDIC 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. Modification of the July 2014 Order was announced by the NDIC in the fourth quarter of 2015, resulting in the existing January 1, 2015 gas capture rate of 77% being extended to April 1, 2016 and updated gas capture rates of 80% by April 1, 2016, 85% by November 1, 2016, 88% by November 1, 2018 and 91% by November 1, 2020. The July 2014 Order established an enforcement mechanism for policy recommendations that were previously adopted by the NDIC in March 2014. Those recommendations required all E&P 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 gas capture percentage goals. In particular, the July 2014 Order provided that after an initial 90-day period, wells must meet or exceed the NDIC'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. As of December 31, 2016, we were capturing approximately 87% of our natural gas production in North Dakota. While we were in compliance with these requirements as of December 31, 2016 and expect to remain in compliance in the future, there is no assurance that we will remain in compliance in the future or that such future compliance will not have a material adverse effect on our business and results of operations.

Climate change

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration by states or groupings of states of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

Table of Contents

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and has 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. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, onshore and offshore oil and natural gas production facilities and onshore processing, transmission, storage and distribution facilities, which include certain of our operations. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rules with the NSPS.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published NSPS, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. Moreover, in November 2016, the EPA issued a final information collection request (“ICR”) seeking information about methane emissions from facilities and operations in the oil and natural gas industry. The EPA has indicated that it intends to use the information from this request to develop Existing Source Performance Standards for the oil and natural gas industry. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France to prepare an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016. The United States is one of more than 120 nations having ratified or otherwise consented to the agreement; however, this agreement does not create any binding obligations for nations to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that require reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur increased costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax, which one or more developments could have an adverse effect on our business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and natural gas we or our customers produce and lower the value of our reserves as well as reduce demand for our midstream services. Finally, it should be noted 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 such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities because of climate related damages to our facilities, our costs of operations potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by such climate effects, or increased costs for insurance coverage in the aftermath of such effects. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Water discharges

The Federal Water Pollution Control Act (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 EPA has issued final rules outlining its position on the federal jurisdictional reach over waters of the United States. This interpretation by the EPA may constitute an expansion of federal jurisdiction over waters of the United States. The rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015 as that appellate court and several other courts review lawsuits opposing implementation of the rule. In January 2017, the United States Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts. Litigation surrounding this rule is ongoing. To the extent this rule expands the scope of the Clean Water Act's jurisdiction, drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Oil Pollution Act of 1990 ("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 E&P 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. These injection wells are regulated pursuant to the federal Safe Drinking Water Act ("SDWA") Underground Injection Control ("UIC") program and analogous state laws. The UIC program 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 fresh water, 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. Moreover, 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 produced water from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down 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 operational activities, our or our customers' costs to operate may significantly increase and our ability to continue production or conduct midstream services or dispose of produced water may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

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 hydraulic fracturing process is typically regulated by state oil and natural gas commissions or similar agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in February 2014, the EPA asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. The EPA also issued final CAA regulations in 2012 that include NSPS for completions of hydraulically fractured natural gas wells, compressors, controls, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. In June 2016, the EPA published final rules establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified and reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities and is formally seeking additional information from oil and natural gas producing companies as necessary to eventually expand these final rules to include existing equipment and processes. In addition, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants and, in May 2014, published an ANPR regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

From time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states, including North Dakota where we primarily operate, 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 high-volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. 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. 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.

Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to added delays for our operations or increased operating costs in our or our customers’ production of oil and natural gas. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, which could have a material adverse effect on our business or results of operations with respect to E&P activities and midstream services. 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 (“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. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered or threatened species are located in areas of the underlying properties where we or our customers 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 one or more settlements entered into by the U.S. Fish and Wildlife Service (“FWS”), the agency is required to make determinations on the listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us or our customers to incur increased costs arising from species protection measures or could result in delays or limitations on our or our customers’ E&P activities that could have an adverse impact on our ability to develop and produce reserves or an indirect adverse impact on our midstream services.

Operations on federal lands

Performance of oil and natural gas E&P activities on federal lands, including Indian lands and lands administered by the federal BLM are subject to the National Environmental Policy Act (“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 or performance of midstream services. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt our or our customers’ E&P activities. Moreover, depending on the mitigation strategies recommended in the Environmental Assessments or Environmental Impact Statement, we or our customers could incur added costs, which may be significant.

Table of Contents

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 (“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.

Employees

As of December 31, 2016, we employed 477 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, 2016, 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.

Table of Contents

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

Further declines, or extended low commodity prices, 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 $52.99 per barrel to a low of $26.19 per barrel during 2016. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.80 per MMBtu to a low of $1.49 per MMBtu during 2016. 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 E&P activities;
- 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;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas and related infrastructure;
- 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 estimated net oil and natural gas reserves” below. 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 estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves” below.

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 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 Notes (as defined in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and capital resources”). If amounts outstanding under our revolving credit facility or our 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 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 Notes (as defined in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources”) 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 debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- 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.

Table of Contents

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indentures governing our Senior 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 Notes or any future indebtedness could result in an event of default under our revolving credit facility, the indentures governing our Senior 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 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 90% 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, 2016, we had $363.0 million of outstanding borrowings and had $12.3 million of outstanding letters of credit under our revolving credit facility, $774.7 million available for future secured borrowings under our revolving credit facility and $2,053.0 million outstanding in 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", "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Senior unsecured notes" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Senior unsecured convertible 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;
- 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

Table of Contents

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.

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.

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 E&P 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 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” 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, 2016, 2015 and 2014.

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, 2016, 2015 and 2014, 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.

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.

If oil and natural gas prices remain at their current level for an extended period of time or 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. A further decline in oil and natural gas prices may cause us to

Table of Contents

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 for impairment as of December 31, 2016 and 2015. For the years ended December 31, 2016 and 2015, we recorded an impairment loss of $1.1 million and $9.4 million, respectively, to adjust the carrying values of our proved oil and natural gas properties held for sale to their estimated fair values. For the year ended December 31, 2014, we 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. During the years ended December 31, 2016, 2015 and 2014, we recorded non-cash impairment charges of $1.1 million, $36.6 million and $7.3 million, respectively, on our unproved properties due to expiring leases and periodic assessments of our unproved properties.

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.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment, supplies and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. 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 NDIC 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, successfully cleaning out the well bore after completion of the final fracture stimulation stage and successfully protecting nearby producing wells from the impact of fracture stimulation.

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. Excluding acquisitions of $781.5 million in 2016 and $28.7 million in 2015, we spent $400.0 million and $581.3 million related to capital expenditures for the years ended December 31, 2016 and 2015, respectively. Our capital expenditure budget for 2017 is approximately $605 million, with approximately $410 million allocated for drilling and completion operations. Since our initial public offering, our capital expenditures have been financed with proceeds from public equity offerings,

proceeds from our issuance of Notes, borrowings under our revolving credit facility, net cash provided by operating activities, the sale of non-core oil and gas properties and cash settlements of derivative contracts. DeGolyer and MacNaughton projects that we will incur capital costs of $702.0 million over the next five years to develop the proved undeveloped reserves in the Williston Basin covered by its December 31, 2016 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.

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, borrowings under our revolving credit facility and cash settlements of derivative contracts; 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: