PIONEER NATURAL RESOURCES CO
Form 10-K
February 19, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2014
or

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

For the transition period from to
Commission File Number: 1-13245
Pioneer Natural Resources Company
(Exact name of registrant as specified in its charter)

Delaware	75-2702753
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5205 N. O'Connor Blvd., Suite 200, Irving, Texas	75039
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (972) 444-9001
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.01	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 (§229.405 of this chapter) 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 o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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	$32,612,539,563
Number of shares of Common Stock outstanding as of February 13, 2015	148,963,753

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Shareholders to be held during May 2015 are incorporated into Part III of this report.

Table of Contents

TABLE OF CONTENTS

Table of Contents
TABLE OF CONTENTS

Table of Contents

Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

- "Bbl" means a standard barrel containing 42 United States gallons.
- "Bcf" means one billion cubic feet.
- "BOE" means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of gas to one Bbl of oil or natural gas liquid.
- "BOEPD" means BOE per day.
- "Btu" means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- "CBM" means coal bed methane.
- "Conway" means the daily average natural gas liquids components as priced in Oil Price Information Services ("OPIS") in the table "U.S. and Canada LP – Gas Weekly Averages" at Conway, Kansas.
- "DD&A" means depletion, depreciation and amortization.
- "Field fuel" means gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.
- "GAAP" means accounting principles that are generally accepted in the United States of America.
- "LIBOR" means London Interbank Offered Rate, which is a market rate of interest.
- "MBbl" means one thousand Bbls.
- "MBOE" means one thousand BOEs.
- "Mcf" means one thousand cubic feet and is a measure of gas volume.
- "MMBbl" means one million Bbls.
- "MMBOE" means one million BOEs.
- "MMBtu" means one million Btus.
- "MMcf" means one million cubic feet.
- "Mont Belvieu" means the daily average natural gas liquids components as priced in OPIS in the table "U.S. and Canada LP – Gas Weekly Averages" at Mont Belvieu, Texas.
- "NGL" means natural gas liquid.
- "NYMEX" means the New York Mercantile Exchange.
- "NYSE" means the New York Stock Exchange.
- "Pioneer" or the "Company" means Pioneer Natural Resources Company and its subsidiaries.
- "Pioneer Southwest" means Pioneer Southwest Energy Partners L.P. and its subsidiaries.
- "Proved developed reserves" mean reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
- "Proved reserves" mean those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Table of Contents

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- "Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

- "SEC" means the United States Securities and Exchange Commission.
- "Standardized Measure" means the after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs employed in the determination of proved reserves and a ten percent discount rate.
- "U.S." means United States.
- "VPP" means volumetric production payment.
- "WTI" means West Texas intermediate, a light, sweet blend of oil produced from fields in western Texas.
- With respect to information on the working interest in wells, drilling locations and acreage, "net" wells, drilling locations and acres are determined by multiplying "gross" wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
- Unless otherwise indicated, all currency amounts are expressed in U.S. dollars.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different from the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market

Risk" for a description of various factors that could materially affect the ability of Pioneer to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

PART I

ITEM 1. BUSINESS

General

The Company is a large independent oil and gas exploration and production company with operations in the United States. Pioneer is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Pioneer's common stock is listed and traded on the NYSE under the ticker symbol "PXD."

The Company is a Delaware corporation formed in 1997. The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039. The Company's telephone number is (972) 444-9001. The Company maintains other offices in Denver, Colorado and Midland, Texas. At December 31, 2014, the Company had 4,075 employees, 1,795 of whom were employed in field and plant operations and 848 of whom were employed in vertical integration activities.

Available Information

Pioneer files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC. The public can obtain any documents that Pioneer files with the SEC at http://www.sec.gov.

The Company also makes available free of charge through its Internet website (www.pxd.com) its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC. In addition to the reports filed or furnished with the SEC, Pioneer publicly discloses material information from time to time in its press releases, at annual meetings of stockholders, in publicly accessible conferences and investor presentations, and through its website (principally in the Investors pages).

Mission and Strategies

The Company's mission is to enhance shareholder investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility, capital allocation discipline and enhancing net asset value through accretive drilling programs, joint ventures and acquisitions. These strategies are anchored by the Company's interests in the long-lived Spraberry/Wolfcamp oil field; the liquid-rich Eagle Ford Shale play; the West Panhandle gas and liquids field; and the Raton gas field; which together have an estimated remaining productive life in excess of 40 years. Underlying these fields are 98 percent of the Company's total proved oil and gas reserves as of December 31, 2014.

Business Activities

The Company is an independent oil and gas exploration and production company. Pioneer's purpose is to competitively and profitably explore for, develop and produce oil and gas reserves. In so doing, the Company sells homogenous oil, NGL and gas units that, except for geographic and relatively minor quality differences, cannot be significantly differentiated from units offered for sale by the Company's competitors. Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management.

Petroleum industry. North American oil prices had been fairly stable during the past three years despite the significant increase in United States oil production from unconventional shale plays. During such time, the growth in North American oil production had been offset by reduced oil imports, keeping supply and demand fairly balanced in the United States. On an international level, the geopolitical factors negatively impacting international oil supplies were offset by the decline in United States imports, resulting in generally stable world oil prices. During the second half of 2014, however, as United States production continued to surge, worldwide demand was sluggish, reflecting the decline in the Chinese growth rate, the lingering recession in Europe and weaker economic performance in other regions, resulting in a worldwide oversupply of oil and oil price weakness. During the fourth quarter of 2014, members of the Organization of Petroleum Exporting Countries ("OPEC") decided to maintain production quotas at current levels despite production outpacing demand. This caused oil prices, which had already been declining, to decrease significantly in December 2014. The market oversupply of oil is expected to continue in 2015, with oil prices expected to remain under pressure. The growth of unconventional shale drilling has also substantially increased the supply of NGLs, resulting in a significant decline in NGL component prices as the supply of such products has grown. While more export facilities have been built and NGL exports are increasing, the overall United States demand for NGL products has not kept pace with the supply of such products; consequently, prices for NGL products have generally declined over the past three years. North American gas prices have remained volatile and they trended lower from 2009 through 2012, but improved steadily throughout 2013 and 2014 before dropping significantly in the fourth quarter of 2014. The decline in North American gas prices from 2009 through 2012 was primarily a result of significant discoveries of gas and associated gas reserves in United States gas, oil and liquid-rich shale plays, combined with the warmer than normal winters, which resulted in gas storage levels being at historically high levels, and minimal economic demand growth in the United States. The increases in gas prices during the latter part of 2013 and the majority of 2014 were primarily related to reduced drilling activity in gas shale plays and demand increases as a result of colder late 2013 and early 2014 winter weather, which reduced storage levels. The recent gas price decrease during the fourth quarter of 2014 reflects expectations for a warmer than normal winter, which is expected to result in gas storage levels being higher than normal at the end of the winter draw season and an expectation that there will be an oversupply of gas during 2015.

Oil prices continue to be primarily driven by world supply and demand fundamentals. Recent increases in United States oil, NGL and gas production volumes from the Permian Basin, Eagle Ford, Bakken, Marcellus and Utica areas have been met with lower demand, the decades-old ban on oil exports, higher storage levels and pipeline, gas plant and NGL fractionation infrastructure capacity limitations. These factors have led to a reduction in United States NYMEX oil, NGL and gas prices compared to international prices for similar commodities, including Brent oil prices. Since 2010, the economies in the United States and certain other countries have continued to stabilize with resulting improvements in industrial demand and consumer confidence. However, other economies, such as those of certain European and Asian nations, continue to face economic struggles or slowing economic growth. While the outlook for a continued worldwide economic recovery remains cautiously optimistic, its timing and strength is still uncertain; therefore, the likelihood of a sustained recovery in worldwide demand for energy is difficult to predict. As a result, the Company believes it is likely that commodity prices will continue to be volatile during 2015.

Significant factors that will affect 2015 commodity prices include: the impact of announced capital spending decreases on forecasted United States oil, NGL and gas supplies; the ongoing effect of economic stimulus initiatives; fiscal challenges facing the United States federal government and potential changes to the tax laws in the United States; continuing economic struggles in European and Asian nations; political and economic developments in North Africa and the Middle East; demand from Asian and European markets; the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas; the capacity of United States refiners to absorb increasing domestic supplies of oil and condensate; potential export regulatory changes in the United States; the supply and demand fundamentals for NGLs in the United States and the pace at which export capacity grows; and overall North American gas supply and demand fundamentals, including gas storage levels that are anticipated to be higher than normal at the end of the winter draw season.

Pioneer uses commodity derivative contracts to mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities and its net asset value. Although the Company has entered into commodity derivative contracts for a large portion of its forecasted production through 2015, a sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Company could enter into derivative contracts on additional volumes in the future. As a result, the Company's internal cash flows would be reduced for affected periods. A sustained decline in commodity prices could result in a shortfall in expected cash flows, which could negatively affect the Company's liquidity, financial position and future results of operations. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's open derivative positions as of December 31, 2014, and subsequent changes to these positions.

The Company. The Company's growth plan is primarily anchored by horizontal drilling in the Spraberry/Wolfcamp oil field located in West Texas and the liquid-rich Eagle Ford Shale field located in South Texas. Complementing these growth areas, the Company has oil and gas production activities and development opportunities in the Raton gas field located in southern Colorado, the West Panhandle gas and liquids field located in the Texas Panhandle and the Edwards gas field located in South Texas. Combined, these assets create a portfolio of resources and opportunities that are well balanced and diversified among oil, NGL and gas, and that are also well balanced among long-lived, dependable production and lower-risk exploration and development opportunities. The Company has a team of dedicated employees who represent the professional disciplines and sciences that the Company believes are necessary to allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGLs and gas through development drilling, production enhancement activities and acquisitions of producing properties, while minimizing the controllable costs associated with the production activities. For the year ended December 31, 2014, the Company's production from continuing operations of 67 MMBOE, excluding field fuel usage, represented an 18 percent increase over production from continuing operations during 2013. Production, price and cost information with respect to the Company's properties for 2014, 2013 and 2012 is set forth in "Item 2. Properties — Selected Oil and Gas Information — Production, price and cost data."

Development activities. The Company seeks to increase its proved oil and gas reserves, production and cash flow through development drilling and by conducting other production enhancement activities, such as well recompletions. During the three years ended December 31, 2014, the Company drilled 1,423 gross (1,242 net) development wells, 99 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $4.9 billion.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2014 include proved undeveloped reserves and proved developed reserves that are behind pipe of 89 MMBbls of oil, 42 MMBbls of NGLs and 317 Bcf of gas. The Company believes that its proved reserves represent a significant portfolio of development opportunities. The timing of the development of these reserves will be dependent upon commodity prices, drilling and operating costs and the Company's expected operating cash flows and financial condition.

Exploratory activities. The Company has devoted significant efforts and resources to hiring and developing a highly skilled geoscience staff as well as acquiring a significant portfolio of lower-risk exploration opportunities that are expected to be evaluated and tested over the next decade and beyond. Exploratory and extension drilling involve greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities. See "Item 1A. Risk Factors — Exploration and development drilling may not result in commercially productive reserves" below.

Integrated services. The Company continues to benefit from its integrated services to control drilling and operating costs and support the execution of its drilling program and operating activities. The Company has Company-owned fracture stimulation fleets totaling approximately 360,000 horsepower supporting drilling operations in the Spraberry/Wolfcamp and Eagle Ford Shale areas. The Company also owns other field service equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In April 2012, Pioneer acquired a large U.S. industrial sands company, which was renamed Premier Silica (see Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the acquisition of Premier Silica). That acquisition secured a high-quality, low-cost and logistically advantaged brown sand supply for Pioneer to use for its growing fracture stimulation requirements in the Spraberry/Wolfcamp field.

Acquisition activities. The Company regularly seeks to acquire properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. In addition, the Company pursues strategic acquisitions that will allow the Company to expand into new geographical areas that provide future exploration/exploitation opportunities. During 2014, 2013 and 2012, the Company spent $104 million, $76 million and $158 million, respectively, to purchase primarily undeveloped acreage for future exploitation and exploration activities.

In December 2014, the Company acquired the remaining limited partner interests in five affiliated partnerships for $54 million and caused the partnerships to be merged with and into the Company. In addition, in December 2013, the Company completed the acquisition of all of the outstanding common units of Pioneer Southwest not already owned by the Company in exchange for 3.96 million shares of the Company's common stock through a merger of a wholly-owned subsidiary of the Company into Pioneer Southwest, the result of which was that Pioneer Southwest became a wholly-owned subsidiary of the Company. The 2014 and 2013 mergers enhance the Company's (i) ability to fully and optimally develop the Company's Spraberry/Wolfcamp properties in the Midland Basin in West Texas utilizing horizontal drilling and (ii) organizational, operational and administrative efficiencies.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas assets or entities owning oil and gas assets and opportunities to engage in mergers, consolidations or other business combinations with such entities) and at any given time may be in various stages of evaluating such opportunities. Such stages may take the form of internal financial analyses, oil and gas reserve analyses, due diligence, the submission of indications of interest, preliminary negotiations, negotiation of letters of intent or negotiation of definitive agreements. The success of any acquisition is uncertain and depends on a number of factors, some of which are outside the Company's control. See "Item 1A. Risk Factors — The Company may be unable to make attractive acquisitions and any acquisition it completes is subject to substantial risks that could adversely affect its business."

Asset divestitures and discontinued operations. The Company regularly reviews its asset base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While the Company generally does not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering the Company's objective of increasing financial flexibility through reduced debt levels.

EFS Midstream. In November 2014, the Company announced that it is pursuing the divestment of its 50.1 percent share of EFS Midstream LLC ("EFS Midstream"). The Company is marketing its equity investment in EFS Midstream and no assurance can be given that a sale will be completed in accordance with the Company's plans or on terms and at a price acceptable to the Company.

Hugoton. In September 2014, the Company completed the sale of its net assets in the Hugoton field in southwest Kansas for cash proceeds of $328 million, including normal closing adjustments.

Barnett Shale. During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. In September 2014, the Company completed the sale of its Barnett Shale net assets for cash proceeds of $150 million, including normal closing adjustments.

Alaska. During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer's Alaska subsidiary ("Pioneer Alaska"). In April 2014, the Company completed the sale of Pioneer Alaska for cash proceeds of $267 million, including normal closing and other adjustments.

South Africa. During the first quarter of 2012, the Company agreed to sell its net assets in South Africa ("Pioneer South Africa"), effective January 1, 2012, for $60 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for cash proceeds of $16 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale.

The Company has reflected its Hugoton, Barnett Shale, Pioneer Alaska and Pioneer South Africa results of operations as discontinued operations in the accompanying consolidated statements of operations.

Sendero. During December 2013, the Company committed to a plan to sell the Company's majority interest in Sendero Drilling Company, LLC ("Sendero") to Sendero's minority interest owner. At December 31, 2013, the assets and liabilities of Sendero were classified as held for sale at their estimated fair value. In March 2014, the Company completed the sale of Sendero for cash proceeds of $31 million. As part of the sales agreement, the Company committed to lease from Sendero 12 vertical rigs through December 31, 2015 and eight vertical rigs in 2016.

Southern Wolfcamp. In January 2013, the Company signed an agreement with Sinochem Petroleum USA LLC ("Sinochem") to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas for consideration of $1.8 billion. In May 2013, the Company completed the sale for cash proceeds of $624 million, which resulted in a gain of $181 million related to the unproved property interests conveyed to Sinochem. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the southern portion of the horizontal Wolfcamp Shale play. At December 31, 2014, the unused carry balance totaled $575 million.

The Company anticipates that it will continue to sell nonstrategic properties or other assets from time to time to increase capital resources available for other activities, to achieve operating and administrative efficiencies and to improve profitability. See Notes C and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures, impairments and discontinued operations. Also see "Item 1A. Risk Factors - The Company's ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond its control, and in certain cases the Company may be required to retain liabilities for certain matters" for discussion of risk factors associated with the completion of divestitures.

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of operations and price risk.

Significant purchasers. During 2014, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (24 percent), Occidental Energy Marketing Inc. (13 percent), Enterprise Products Partners L.P. (11 percent) and Valero Marketing and Supply Company (10 percent). The Company believes the loss of a significant purchaser or an inability to secure adequate pipeline, gas plant and NGL fractionation infrastructure in its key producing areas could have a material adverse effect on its ability to sell its oil, NGL and gas production. See "Item 1A. Risk Factors" and Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about significant customer and infrastructure capacity risks.

Derivative risk management activities. The Company primarily utilizes commodity swap contracts, collar contracts and collar contracts with short puts to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company also, from time to time, utilizes interest rate derivative contracts to reduce the effect of interest rate volatility on the Company's indebtedness. The Company accounts for its derivative contracts using the mark-to-market ("MTM") method of accounting. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's derivative risk management activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information about the impact of commodity derivative activities on oil, NGL and gas revenues and net derivative gains and losses during 2014, 2013 and 2012, as well as the Company's open commodity derivative positions at December 31, 2014, and subsequent changes to these positions.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive. A large number of companies, including major integrated and other independent companies, and individuals engage in the exploration for and development of oil and gas properties, and there is a high degree of competition for oil and gas properties suitable for development or exploration. Acquisitions of oil and gas properties have been an important element of the Company's growth. The Company intends to continue acquiring oil and gas properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, evaluate and acquire such properties and the financial resources necessary to acquire and develop the properties. Some of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company.

Markets. The Company's ability to produce and market oil, NGLs and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect these commodity prices or the degree to which these prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production.

Securities regulations. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the SEC and the NYSE. This regulatory oversight imposes on the Company the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting, and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the rules and regulations of the SEC could subject the Company to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of the Company's common stock, which would have an adverse effect on the market price and liquidity of the Company's common stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

Environmental and occupational health and safety matters. The Company's operations are subject to stringent and complex federal, state and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions to achieve and maintain compliance and imposing sanctions, including administrative, civil and criminal penalties, for any failure to comply.

These laws and regulations may, among other things:

- require the acquisition of various permits before drilling or other regulated activity commences;

- enjoin some or all of the operations of facilities deemed in noncompliance with permits;
- restrict the types, quantities and concentration of various substances that may be released into the environment in connection with oil and gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- impose specific criteria addressing worker protection;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and

- impose substantial liabilities for pollution resulting from operations.

These laws and regulations may also restrict the rate of oil and 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. Additionally, the U.S. Congress, state legislatures and federal and state regulatory agencies frequently revise environmental laws and regulations, and the trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment. Any changes that result in more stringent and costly drilling, completion, construction or water management activities, or waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant effect on the Company's capital and operating costs.

The following is a summary of some of the more significant laws and regulations to which the Company's business operations are or may be subject. These laws may be amended from time to time.

Waste handling. The federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. While drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions, it is possible that such exploration and production wastes may, in the future, be classified as hazardous wastes. Any such change could result in an increase in the Company's costs to manage and dispose of wastes, which could have a material adverse effect on the Company's results of operations and financial position. In the course of its operations, the Company generates some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. Wastes containing naturally occurring radioactive materials ("NORM") may also be generated in connection with the Company's operations. NORM is subject primarily to individual state radiation control regulations. In addition, NORM handling and management activities are governed by regulations promulgated by the federal Occupational Safety and Health Administration ("OSHA"). These state and OSHA regulations impose certain requirements concerning worker protection, with respect to NORM, the treatment, storage and disposal of NORM waste, the management of waste piles, containers and tanks containing NORM and restrictions on the uses of land with NORM contamination.

Comprehensive Environmental Response, Compensation, and Liability Act. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and analogous state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the 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. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company currently owns or leases numerous properties that have been used for oil and gas exploration and production for many years. Although the Company believes it has used operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on or under the properties owned or leased by the Company, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. In addition, some of the Company's properties have been operated by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Certain of these properties have had historical petroleum spills or releases. All of such properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. If a surface spill or release were to occur, the Company expects that it would be controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions and by using the Company's spill prevention, control and countermeasure ("SPCC") plans or other spill or emergency contingency plans that it maintains in accordance with EPA requirements.

Water discharges and use. The federal Water Pollution Control Act, also known as the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. SPCC planning requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The primary federal law imposing liability for oil spills is the Oil Pollution Act ("OPA"), which amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. OPA applies to vessels, offshore facilities and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil spill cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. If an oil spill subject to the requirements of OPA were to occur at a Company property, the Company expects that it would be controlled, contained and remediated in accordance with the applicable requirements of OPA and by using the Company's OPA spill response plan together with the assistance of trained first responders and any oil spill response contractor that the Company would have engaged pursuant to OPA to address such oil spills.

Fluids associated with oil and gas production, consisting primarily of salt water, result from operations on the Company's properties and are disposed by injection in underground disposal wells. These disposal wells are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") and analogous state and local laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of the Company's disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. Currently, the Company believes that disposal well operations on the Company's properties substantially comply with all applicable requirements under the SDWA. However, a change in the regulations or the inability to obtain permits for new disposal wells in the future may affect the Company's ability to dispose of produced waters and ultimately increase the cost of the Company's operations. For example, there exists a growing concern that the injection of salt water and other fluids into underground disposal wells triggers seismic activity in certain areas, including in some parts of Texas, where the Company operates. In response to these concerns, in October 2014, the Texas Railroad Commission (the "TRC") published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or perhaps may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs.

The Company also uses hydraulic fracturing techniques in virtually all of its drilling and completion programs, and development of its properties is dependent on the Company's ability to hydraulically fracture the producing formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the federal Bureau of Land Management (the "BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands, and the agency is now analyzing comments

to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.
From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In addition to any actions by the U.S. Congress, certain states in which the Company operates, including Colorado and Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Also, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. For example, in response to concerns regarding hydraulic fracturing, the city of Denton, Texas issued a moratorium on the issuance of new drilling permits inside the Denton city limits.The Company believes that it follows applicable standard industry practices and legal requirements for groundwater protection in its hydraulic fracturing activities. Nonetheless, in the event federal, state or local restrictions are adopted in areas where the Company is currently conducting, or in the future plans to conduct operations, the

Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development or production activities, and be limited or precluded in the drilling of wells or in the amounts that the Company is ultimately able to produce from its reserves.

Certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and a draft report is expected to be available for public comments and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

The water produced by the Company's CBM operations also may be subject to the state laws and regulations of regulatory bodies regarding the ownership and use of water. For example, in connection with the Company's CBM operations in the Raton Basin in Colorado, water is removed from coal seams to reduce pressure and allow the methane to be recovered. Historically, these operations have been regulated by the state agency responsible for regulating oil and gas activity in the state. Nevertheless, in 2009, the Colorado Supreme Court affirmed a state court holding that water produced in connection with the CBM operations should be subject to state water-use regulations administered by a different agency that regulates other uses of water in the state, including requirements to obtain permits for diversion and use of surface and subsurface water, an evaluation of potential competing uses of the water, and a possible requirement to provide mitigation water for other water users. The Colorado legislature and state agency adopted laws and regulations in response to this ruling. These and other resulting changes in the regulation of water produced from CBM operations may have an adverse effect on the costs of doing business and the ability to expand operations by the Company or other CBM producers.

Air emissions. The Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain or strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions of certain air pollutants. Moreover, states may impose their own air emissions limitations, which may be more stringent than the federal standards imposed by the EPA. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for noncompliance with air permits or other requirements of the CAA and associated state laws and regulations. The adoption of laws, regulations, orders or other legally enforceable mandates governing oil and gas drilling and operating activities in the areas where the Company conducts business that result in more stringent emissions standards could increase the Company's costs or reduce its volume of production, which could have a material adverse effect on the Company's results of operations and cash flows.

Moreover, permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require the Company to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies for oil and gas exploration and production operations. For example, in 2012, the EPA published final rules under the CAA that subject oil and gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regard to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells by using reduced emission completions, also known as "green completions," after January 1, 2015. These regulations also establish specific new requirements regarding emissions from certain production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. Compliance with these requirements could increase the Company's costs of development and production, which costs could be significant.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on species listed as threatened or endangered under the ESA. Some of the Company's operations are conducted in areas where protected species or their habitats are known to exist. In these areas, the

Company may be obligated to develop and implement plans to avoid potential adverse effects to protected species and their habitats, and the Company may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when the Company's operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where the Company performs activities could result in increased costs or limitations on the Company's ability to perform operations and thus have an adverse effect on the Company's business.

Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service (the "FWS") is required to make a determination on the potential listing of numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Company operates could cause the Company to incur increased costs arising from species protection measures or could result in limitations on the Company's drilling and production activities that could have an adverse effect on the Company's ability to develop and produce its reserves. For example, on March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas and Colorado, where the Company conducts operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties, including the Company, agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The listing of the lesser prairie chicken as a threatened species or, alternatively, entry into certain range-wide conservation planning agreements such as WAFWA, could result in increased costs to the Company from species protection measures, time delays or limitations on the Company's activities, which costs, delays or limitations may be significant to the Company's business.

Activities on federal lands. Oil and gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having 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. Currently, the Company has minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay or limit, or increase the cost of, the development of oil and gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Occupational health and safety. The Company's operations are subject to the requirements of OSHA and comparable state statutes. These laws and the related regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and similar state statues require that the Company organize or disclose information about hazardous materials used or produced in the Company's operations. In addition, the Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. The Company believes that it is in substantial compliance with these applicable standards and with OSHA and comparable requirements.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the CAA that, among other things, establish certain permits and construction reviews designed to allow operations while ensuring the Prevention of Significant Deterioration ("PSD") of air quality by GHG emissions from large stationary sources that already may be potential sources of other regulated pollutant emissions. The Company could become subject to these permitting requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct in the future if they would otherwise emit large volumes of GHGs from such sources. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including certain oil and gas production facilities, which includes certain of the Company's facilities. The Company is monitoring GHG emissions from its operations in accordance with these GHG emissions reporting rules and believes its monitoring activities are in substantial compliance with applicable reporting obligations.

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

The adoption of any legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs from the Company's equipment and operations could require the Company to incur increased operating 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. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015 that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Any such 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 gas the Company produces. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Company's business, financial condition and results of operations. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on the Company's financial condition and results of operations.

Other regulation of the oil and gas industry. The oil and gas industry is regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous federal and state departments and agencies are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase the Company's cost of doing business by increasing the cost of production, the Company believes that these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Development and production. Development and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the method and ability to fracture stimulate wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations at which the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGL and gas within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from the Company's wells, negatively affect the economics of production from these wells, or limit the number of locations the Company can drill.

Regulation of transportation and sale of gas. The availability, terms and cost of transportation significantly affect sales of gas. Federal and state regulations govern the price and terms for access to gas pipeline transportation. Intrastate gas pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies. The interstate transportation and sale of gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). FERC endeavors to make gas transportation more accessible to gas buyers and sellers on an open-access and non-discriminatory basis.

Pursuant to the Energy Policy Act of 2005 ("EPAct 2005") it is unlawful for "any entity," including producers such as the Company, that are otherwise not subject to FERC's jurisdiction under the Natural Gas Act (the "NGA"), to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties of up to $1.0 million per day for each violation of the NGA or the Natural Gas Policy Act of 1978. The anti-manipulation rule applies to activities of entities not otherwise subject to FERC's jurisdiction to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, FERC issued a final rule on the annual gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, any market participant, including a producer such as the Company, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical gas in the previous calendar year must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of 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 704. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on its operations. The Company does not believe that it will be affected by any action taken in a materially different way than other gas producers, gatherers and marketers with which it competes.

Natural gas processing. The Company's gas processing operations are not subject to FERC or state regulation. There can be no assurance that the Company's processing operations will continue to be exempt from regulation in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact the Company's processing business.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC's jurisdiction. The Company believes that its gathering facilities meet the traditional tests FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of the Company's gathering facilities may be subject to change based on future determinations by FERC and the courts. Thus, the Company cannot guarantee that the jurisdictional status of its gas gathering facilities will remain unchanged. While the Company owns or operates some gas gathering facilities, the Company also depends on gathering facilities owned and operated by third parties to gather production from its properties, and therefore the Company is affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, the Company also may be affected by these changes. Accordingly, the Company does not anticipate that the Company would be affected any differently than similarly situated gas producers.

Regulation of transportation and sale of oil and NGLs. The liquids industry is also extensively regulated by numerous federal, state and local authorities. In a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). The Company does not believe these regulations affect it any differently than other producers.

The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65 percent. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to the Company. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that the Company relies upon for liquids transportation could have a material adverse effect on its business, financial condition, results of operations and cash flows. However, the Company believes that access to liquids pipeline transportation services generally will be available to it to the same extent as to its similarly-situated competitors.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. The Company believes that the regulation of liquids pipeline transportation rates will not affect its operations in any way that is materially different from the effects on its similarly-situated competitors.

In November 2009, the Federal Trade Commission (the "FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1.0 million per violation per day. In July 2010, the U.S. Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (the "CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FERC with respect to anti-manipulation in the gas industry and the FTC with respect to oil purchases and sales, as described above. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1.0 million or triple the monetary gain to the person for each violation.

Energy commodity prices. Sales prices of oil, condensate, NGLs and gas are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the U.S. Congress historically has been active in their regulation. The Company cannot predict whether new legislation to regulate oil and gas might actually be enacted by the U.S. Congress or the various state legislatures, and what effect, if any, the proposals might have on the Company's operations.

Transportation of hazardous materials. The federal Department of Transportation has adopted regulations requiring that certain entities transporting designated hazardous materials develop plans to address security risks related to the transportation of hazardous materials. The Company does not believe that these requirements will have an adverse effect on the Company or its operations. The Company cannot provide any assurance that the security plans required under these regulations would protect against all security risks and prevent an attack or other incident related to the Company's transportation of hazardous materials.

ITEM 1A. RISK FACTORS

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities. Other risks are described in "Item 1. Business — Competition, Markets and Regulations," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." These risks are not the only risks facing the Company. The Company's business could also be affected by additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial. If any of these risks actually occurs, it could materially harm the Company's business, financial condition or results of operations and impair the Company's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Company's common stock could decline.

The prices of oil, NGLs and gas are highly volatile. A sustained decline in these commodity prices could adversely affect the Company's business, financial condition and results of operations.

The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on commodity prices. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGLs and gas, market uncertainty and a variety of additional factors that are beyond the Company's control, such as:

- domestic and worldwide supply of and demand for oil, NGLs and gas;
- inventory levels at Cushing, Oklahoma, the benchmark for WTI oil prices, and the United States Gulf Coast;
- oil, NGL and gas inventory levels in the United States;
- the capacity of U.S. refiners to absorb increasing domestic supplies of oil and condensate;
- weather conditions;
- overall domestic and global political and economic conditions, including laws, regulations and administrative policies that restrict the export of the Company's products;

- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- the effect of liquefied natural gas deliveries to and exports from the United States;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the effect of energy conservation efforts;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, commodity prices have been extremely volatile, and the Company expects this volatility to continue. For the five years ended December 31, 2014, oil prices fluctuated from a high of $113.93 per Bbl in 2011 to a low of $53.27 per Bbl in 2014, while gas prices fluctuated from a low of $1.91 per Mcf in 2012 to a high of $6.15 per Mcf in 2014. Recently, commodity prices have declined significantly. Through February 13, 2015, oil prices have declined from a high of $107.26 per Bbl on June 20, 2014 to $44.45 per Bbl on January 28, 2015, and gas prices have declined from a high of $6.15 per Mcf on February 19, 2014 to a low of $2.58 per Mcf on February 6, 2015. Likewise, NGLs have suffered significant recent declines. NGLs are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in commodity prices could materially and adversely affect the Company's future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. The Company makes price assumptions that are used for planning purposes, and a significant portion of the Company's cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, the Company's financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

Significant or extended price declines could also adversely affect the amount of oil, NGLs and gas that the Company can produce economically, which may result in the Company having to make significant downward adjustments to its estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require the Company to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect the Company's ability to replace its production and its future rate of growth.

The Company could experience periods of higher costs if commodity prices rise. These increases could reduce the Company's profitability, cash flow and ability to complete development activities as planned.

Historically, the Company's capital and operating costs have risen during periods of increasing oil, NGL and gas prices. These cost increases result from a variety of factors beyond the Company's control, such as increases in the cost of electricity, steel and other raw materials that the Company and its vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Increased levels of drilling activity in the oil and gas industry in recent periods have led to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in the Company's revenue, thereby negatively impacting the Company's profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that the Company's ability to participate in the commodity price increases is limited by its derivative risk management activities.

The Company's derivative risk management activities could result in financial losses.

To mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities, support the Company's annual capital budgeting and expenditure plans and reduce commodity price risk associated with certain capital projects, the Company's strategy is to enter into derivative arrangements covering a portion of its oil, NGL and gas production. These derivative arrangements are subject to MTM accounting treatment, and the changes in fair market value of the contracts are reported in the Company's statements of operations each quarter, which may result in significant noncash gains or losses. These derivative contracts may also expose the Company to risk of financial loss in certain circumstances, including when:

- production is less than the contracted derivative volumes;
- the counterparty to the derivative contract defaults on its contract obligations; or
- the derivative contracts limit the benefit the Company would otherwise receive from increases in commodity prices.

On the other hand, failure to protect against declines in commodity prices exposes the Company to reduced liquidity when prices decline.

The failure by counterparties to the Company's derivative risk management activities to perform their obligations could have a material adverse effect on the Company's results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. If any of these counterparties were to default on its obligations under the

Company's derivative arrangements, such a default could have a material adverse effect on the Company's results of operations, and could result in a larger percentage of the Company's future production being subject to commodity price changes.

Table of Contents

Exploration and development drilling may not result in commercially productive reserves.
Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled, or become costlier, as a result of a variety of factors, including:

- unexpected drilling conditions;
- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- restricted access to land for drilling or laying pipelines; and
- access to, and the cost and availability of, the equipment, services, resources and personnel required to complete the Company's drilling, completion and operating activities.

The Company's future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental, extension or exploratory, involves these risks, exploratory and extension drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. The Company expects that it will continue to experience exploration and abandonment expense in 2015.
Future price declines could result in a reduction in the carrying value of the Company's proved oil and gas properties, which could adversely affect the Company's results of operations.
Recently, commodity prices have declined significantly. Through February 13, 2015, oil prices have declined from a high of $107.26 per Bbl on June 20, 2014 to $44.45 per Bbl on January 28, 2015, and gas prices have declined from a high of $6.15 per Mcf on February 19, 2014 to a low of $2.58 per Mcf on February 6, 2015. Likewise, NGLs have suffered significant recent declines. NGLs are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. As stated above, price declines, as have occurred recently, could result in the Company having to make downward adjustments to its estimated proved reserves. It is possible that prices could decline further, or the Company's estimates of production or other economic factors could change to such an extent that the Company may be required to impair, as a noncash charge to earnings, the carrying value of the Company's oil and gas properties. The Company is required to perform impairment tests on proved oil and gas properties whenever events or changes in circumstances indicate that the carrying value of proved properties may not be recoverable. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of the Company's oil and gas properties, the carrying value may not be recoverable and therefore an impairment charge would be required to reduce the carrying value of the proved properties to their fair value. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's impairments. The Company may incur impairment charges in the future, which could materially affect the Company's results of operations in the period incurred.
The Company periodically evaluates its unproved oil and gas properties and could be required to recognize noncash charges in the earnings of future periods.
At December 31, 2014, the Company carried unproved oil and gas property costs of $159 million. GAAP requires periodic evaluation of these costs on a project-by-project basis. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, and contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods.
The Company periodically evaluates its goodwill for impairment and could be required to recognize noncash charges in the earnings of future periods.
At December 31, 2014, the Company carried goodwill of $272 million. Goodwill is assessed for impairment annually during the third quarter and whenever facts or circumstances indicate that the carrying value of the Company's

goodwill may be impaired, which may require an estimate of the fair values of the reporting unit's assets and liabilities. Those assessments may be affected by (a) additional reserve adjustments both positive and negative, (b) results of drilling activities, (c) management's outlook for commodity prices and costs and expenses, (d) changes in the Company's market capitalization, (e) changes in the Company's weighted average cost of capital and (f) changes in income taxes. If the fair value of the reporting unit's net assets is not sufficient to fully support the goodwill balance in the future, the Company will reduce the carrying value of goodwill for the impaired value, with a corresponding noncash charge to earnings in the period in which goodwill is determined to be impaired.

The Company may be unable to make attractive acquisitions, and any acquisition it completes is subject to substantial risks that could adversely affect its business.

Acquisitions of producing oil and gas properties have from time to time contributed to the Company's growth. The Company's growth following the full development of its existing property base could be impeded if it is unable to acquire additional oil and gas reserves on a profitable basis. Acquisition opportunities in the oil and gas industry are very competitive, which can increase the cost of, or cause the Company to refrain from, completing acquisitions. The success of any acquisition will depend on a number of factors and involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, the recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;
- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which the Company is not indemnified or for which the indemnity the Company receives is inadequate;
- the validity of assumptions about costs, including synergies;
- the effect on the Company's liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management's attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate the Company's growing business and assets.

All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope. As a result, among other risks, the Company's initial estimates of reserves may be subject to revision following an acquisition, which may materially and adversely affect the desired benefits of the acquisition.

The Company's ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond its control, and in certain cases the Company may be required to retain liabilities for certain matters.

From time to time, the Company sells an interest in a strategic asset for the purpose of assisting or accelerating the asset's development. In addition, the Company regularly reviews its property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of such interests or nonstrategic assets or complete announced dispositions, including the receipt of approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and at prices acceptable to the Company.

Sellers typically retain certain liabilities or indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The Company's gas processing operations are subject to operational risks, which could result in significant damages and the loss of revenue.

As of December 31, 2014, the Company owned interests in six gas processing plants and eight treating facilities. The Company is the operator of one of the gas processing plants and all eight of the treating facilities. There are significant risks associated with the operation of gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or improper operation of a gas processing plant or facility could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source.

The Company's operations involve many operational risks, some of which could result in unforeseen interruptions to the Company's operations and substantial losses to the Company for which the Company may not be adequately insured.

The Company's operations, including well stimulation and completion activities, such as hydraulic fracturing, are subject to all the risks normally incident to the oil and gas development and production business, including:

- blowouts, cratering, explosions and fires;
- adverse weather effects;
- environmental hazards, such as gas leaks, oil spills, pipeline and vessel ruptures, encountering NORM, and unauthorized discharges of toxic gases, brine, well stimulation and completion fluids or other pollutants into the surface and subsurface environment;

- high costs, shortages or delivery delays of equipment, labor or other services or water and sand for hydraulic fracturing;
- facility or equipment malfunctions, failures or accidents;
- title problems;
- pipe or cement failures or casing collapses;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield workover and service tools;
- unusual or unexpected geological formations or pressure or irregularities in formations; and
- natural disasters.

The Company's overall exposure to operational risks may increase as its drilling activity expands and as it seeks to directly provide fracture stimulation, water distribution and disposal and other services internally. Any of these risks could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations.

The Company is not fully insured against certain of the risks described above, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance. Additionally, the Company relies to a large extent on facilities owned and operated by third-parties, and damage to or destruction of those third-party facilities could affect the ability of the Company to produce, transport and sell its hydrocarbons.

Part of the Company's strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

The Company's operations involve utilizing some of the latest drilling and completion techniques as developed by it and its service providers. Risks that the Company faces while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that the Company faces while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The results of drilling in emerging areas are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. New discoveries and emerging formations have limited or no production history and, consequently, the Company is more limited in assessing future drilling results in these areas. If the Company's drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and the Company may recognize noncash impairment charges to reduce the carrying value of its unproved properties.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development, exploratory and infill drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2014 include proved undeveloped reserves and proved developed reserves that are behind pipe of 89 MMBbls of oil, 42 MMBbls of NGLs and 317 Bcf of gas. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

Table of Contents

The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gas gathering systems and other transportation, processing, fractionation and refining facilities to market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products.

The marketing of oil, NGLs and gas production depends in large part on the availability, proximity and capacity of pipelines and storage facilities, gas gathering systems and other transportation, processing, fractionation and refining facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, if these systems were unavailable to the Company, or if access to these systems were to become commercially unreasonable, the price offered for the Company's production could be significantly depressed, or the Company could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while it constructs its own facility or awaits the availability of third party facilities. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to store, process, transport, fractionate and sell its oil, NGL and gas production. The Company's plans to develop and sell its oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing and fractionation facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist.

For example, following Hurricanes Gustav and Ike in 2008, certain Permian Basin gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators. The Company was able to produce its oil wells and vent or flare the associated gas; however, there is no certainty the Company will be able to vent or flare gas in the future due to potential changes in regulations. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The Company has periodically experienced high line pressure at its tank batteries, which has occasionally led to the flaring of gas due to the inability of the gas gathering systems in the areas to support the increased gas production. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, the Company may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

To the extent that the Company enters into transportation contracts with gas pipelines that are subject to FERC regulation, the Company is subject to FERC requirements related to use of such capacity. Any failure on the Company's part to comply with FERC's regulations and policies or with an interstate pipeline's tariff could result in the imposition of civil and criminal penalties.

A limited number of companies purchase a majority of the Company's oil, NGLs and gas. The loss of a significant purchaser could have a material adverse effect on the Company's ability to sell its production.

The Company's operations and drilling activity are concentrated in areas of high industry activity, which may affect its ability to obtain the personnel, equipment, services, resources and facilities access needed to complete its development activities as planned or result in increased costs.

The Company's operations and drilling activity are concentrated in areas in which industry activity had increased rapidly, particularly in the Spraberry field in West Texas and the Eagle Ford Shale play in South Texas. As a result, demand for personnel, equipment, power, services and resources, as well as access to transportation, processing and refining facilities in these areas, had increased, as did the costs for those items. In addition, hydraulic fracturing and other operations require significant quantities of water, which supply may be affected by drought conditions. In late 2014, commodity prices began to decline and the demand for goods and services has subsided due to reduced activity in these areas. To the extent that commodity prices improve in the future, any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for the Company to resume or increase its development activities, including the result of any changes in laws or regulations applicable to the Company's operations relating to water usage, could result in oil and gas production volumes being below the Company's forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on the Company's cash flow and profitability.

The refining industry may be unable to absorb rising U.S. oil and condensate production; in such a case, the resulting surplus could depress prices and restrict the availability of markets, which could adversely affect the Company's results of operations.

Under U.S. law and regulations, the export of oil and certain condensates is restricted. Absent a change in this law or an expansion of U.S. refining capacity, rising U.S. production of oil and condensates could result in a surplus of these products, which would likely cause prices for these commodities to fall and markets to constrict. In such circumstances, the returns on the Company's capital projects would decline, possibly to levels that would make execution of the Company's drilling plans uneconomical, and a lack of market for the Company's products could require that the Company shut in some portion of its production. If this were to occur, the Company's production and cash flow could decrease, or could increase less than forecasted, which could have a material adverse effect on the Company's cash flow and profitability.

The nature of the Company's assets and production operations exposes it to significant costs and liabilities with respect to environmental and occupational health and safety matters.

The oil and gas business involves the production, handling, sale and disposal of environmentally sensitive materials and is subject to environmental hazards, such as oil spills, produced water spills, gas leaks, pipeline and vessel ruptures and unauthorized discharges of substances or gases, that could expose the Company to substantial liability due to pollution and other environmental damage. Pollution and similar environmental risks generally are not fully insurable either because such insurance is not available or because of the high premium costs and deductible associated with obtaining such insurance. A variety of federal, state and local laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to administrative, civil or criminal penalties, remedial cleanups, and natural resource damages or other liabilities, and compliance with these laws and regulations may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business — Competition, Markets and Regulations — Environmental and occupational health and safety matters" above for additional discussion related to environmental risks.

Environmental laws and regulations are subject to amendment or replacement by more stringent laws and regulations and no assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or adversely affect the Company's future operations and financial condition.

The Company could incur significant costs and liabilities in responding to contamination that occurs at its properties or as a result of its operations.

There is inherent risk of incurring significant environmental costs and liabilities in the Company's operations due to its handling of petroleum hydrocarbons and wastes, the risk of air emissions and water discharges related to its operations, and operations and waste disposal practices by prior owners and operators. The Company currently owns, leases or operates properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties and could be released during future operations. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons and wastes on, under or from the Company's properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company's operations and facilities where the Company's petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage. The Company may not be able to recover some or any of these costs from insurance or other sources of contractual indemnity.

The Company's credit facility and debt instruments have substantial restrictions and financial covenants that may restrict its business and financing activities.

The Company is a borrower under fixed rate senior notes and maintains a credit facility that is currently undrawn. The terms of the Company's borrowings specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices and interest rates. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt as of December 31, 2014 and the terms associated therewith.

The Company's ability to obtain additional financing is also affected by the Company's debt credit ratings and competition for available debt financing.

The Company faces significant competition, and some of its competitors have resources in excess of the Company's available resources.

The oil and gas industry is highly competitive. The Company competes with a large number of companies, producers and operators in a number of areas such as:

- seeking to acquire oil and gas properties suitable for development or exploration;
- marketing oil, NGL and gas production; and
- seeking to acquire the equipment and expertise, including trained personnel, necessary to evaluate, operate and develop its properties.

Some of the Company's competitors are larger and have substantially greater financial and other resources than the Company. See "Item 1. Business — Competition, Markets and Regulations" for additional discussion regarding competition.

The Company is subject to regulations that may cause it to incur substantial costs.

The Company's operations are subject to stringent and complex federal, state and local laws and regulations governing, among other things, worker health and safety, the discharge of materials into the environment and environmental protection that may cause it to incur substantial costs. For example, in connection with the Company's CBM operations in the Raton Basin in Colorado, the Colorado Supreme Court affirmed a state water court holding that water produced in connection with CBM operations should be subject to state water-use regulations, including regulations requiring permits for diversion and use of surface and subsurface water, an evaluation of potential competing permits, possible uses of the water and a possible requirement to provide augmentation water supplies for water rights owners with more senior rights. As another example, the underground injection well program under the SDWA requires permits from the EPA or an analogous state agency for the Company's disposal wells, establishes minimum standards for injection well operations, and restricts the types and quantities of fluids that may be injected. In some areas of Texas, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the governing Texas regulatory agency is reviewing the data to determine whether any action is necessary to address this issue. If the Texas state agency were to decline to issue permits for, or limit the volumes of, new injection wells into the formations currently utilized by the Company, the Company may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase its costs. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations, including that the Company may be required to suspend drilling operations or shut in production pending compliance. See "Item 1. Business — Competition, Markets and Regulations" for additional discussion regarding government regulation.

The Company's sales of oil, NGLs, gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks.

FERC, the FTC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to the Company's business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to the Company's physical sales of oil, NGLs, gas or other energy commodities, and any derivative activities related to these energy commodities, the Company is required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect the Company's results of operations and financial condition.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities and net cash flows of the Company's proved reserves may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. The estimates of proved reserves and related future net cash flows set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and estimates of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality and quantity of available data;
- the interpretation of that data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance, ad valorem and excise taxes, development costs, transportation costs and workover and remedial costs.

Because all proved reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production costs incurred to recover the reserves;

- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of proved reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to proved reserves will likely be different from estimates, and the differences may be material.

Table of Contents

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on average prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, NGLs and gas; and
- changes in governmental regulations or taxation.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. In general, it requires the use of commodity prices that are based upon a 12-month unweighted average, as well as operating and development costs being incurred at the end of the reporting period. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general. Therefore, the estimates of discounted future net cash flows or Standardized Measure in this Report should not be construed as accurate estimates of the current market value of the Company's proved reserves.

The Company's actual production could differ materially from its forecasts.

From time to time, the Company provides forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Should these estimates prove inaccurate, actual production could be adversely affected. In addition, the Company's forecasts assume that none of the risks associated with the Company's oil and gas operations summarized in this "Item 1A. Risk Factors" occur, such as facility or equipment malfunctions, adverse weather effects, or downturns in commodity prices or significant increases in costs, which could make certain drilling activities or production uneconomical.

The Company's business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, the Company faces various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of the Company's facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected the Company's operations to increased risks that could have a material adverse effect on the Company's business. In particular, the Company's implementation of various procedures and controls to monitor and mitigate security threats and to increase security for the Company's information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company's operations and could have a material adverse effect on the Company's reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage the Company's reputation and lead to financial losses from remedial actions, loss of business or potential liability.

A failure by purchasers of the Company's production to satisfy their obligations to the Company could require the Company to recognize a pre-tax charge in earnings and have a material adverse effect on the Company's results of operation.

The Company relies on a limited number of purchasers to purchase a majority of its products. To the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time. If for any reason the Company were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of the Company's production were uncollectible, the Company would recognize a pre-tax charge in the earnings of that period for the probable loss.

Declining general economic, business or industry conditions could have a material adverse effect on the Company's results of operations.

Since 2010, the economies in the United States and certain other countries have continued to stabilize with resulting improvements in industrial demand and consumer confidence. However, other economies, such as those of certain European and Asian nations, continue to face economic struggles or slowing economic growth and, should these conditions worsen, there could be a significant adverse effect on global financial markets and commodity prices. If the economic climate in the United States or abroad were to deteriorate, demand for petroleum products could diminish, which could depress the prices at which the Company could sell its oil, NGLs and gas and ultimately decrease the Company's net revenue and profitability.

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

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas companies. Such tax legislation changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could have an adverse effect on the Company's financial position, results of operations and cash flows.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces.

In 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the CAA that, among other things, establish certain permits and construction reviews designed to allow operations while ensuring the PSD of air quality by GHG emissions from large stationary sources that already may be potential sources of other regulated pollutant emissions. The Company could become subject to these permitting requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct in the future if they would otherwise emit large volumes of GHGs from such sources. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including certain oil and gas production facilities, which include certain of the Company's facilities. While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from the Company's equipment and operations could require the Company to incur increased operating 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. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Any such 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 gas the Company produces. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Company's business, financial condition and results of operations. See "Item 1. Business - Competition, Markets and Regulations - Environmental and occupational health and safety matters - Climate change" for additional discussion relating to climate change.

The enactment of derivatives legislation could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations for its implementation. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide derivative transactions. As these new position limit rules are not yet final, the impact of those provisions on the Company is uncertain at this time. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require the Company, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although the Company believes it qualifies for the end-user exception from the mandatory clearing requirements for swaps entered to mitigate its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the Company's derivatives. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished or what the effect of any such regulations will be on the Company. For example, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to the Company for capital expenditures, therefore reducing its ability to execute derivatives to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to the Company is uncertain at this time. The full impact of the Dodd-Frank Act and related regulatory requirements upon the Company's business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters and reduce the Company's ability to monetize or restructure its existing derivative contracts. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. The Company's revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company, its financial condition and its results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent the Company transacts with counterparties in foreign jurisdictions, it may become subject to such regulations. At this time, the impact of such regulations is not clear.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company routinely utilizes hydraulic fracturing techniques in the majority of its drilling and completion programs. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the

BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In addition, certain states in which the Company operates, including Colorado and Texas have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and well-construction requirements on hydraulic-fracturing operations. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Also, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. For example, in response to concerns regarding hydraulic fracturing, the city of Denton, Texas issued a moratorium on the issuance of new drilling permits inside the Denton city limits. In the event federal, state or local restrictions are adopted in areas where the Company is currently conducting, or in the future plan to conduct operations, the Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that the Company is ultimately able to produce from its reserves.

Certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and a draft report is expected to be available for public comment and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. See "Item 1. Business - Competition, Markets and Regulations - Environmental and occupational health and safety matters" for additional discussion related to environmental risks associated with the Company's hydraulic fracturing activities.

Laws and regulations pertaining to threatened and endangered species could delay or restrict the Company's operations and cause it to incur substantial costs.

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the ESA, the Migratory Bird Treaty Act, the CWA, OPA and CERCLA. The FWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. For example, on March 27, 2014, the FWS announced the listing of the lesser prairie chicken as a threatened species under the ESA. The lesser prairies chicken's habitat is over a five-state region, including Texas and Colorado, where we conduct operations. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in delays or limitations on its development and production activities that could have an adverse effect on the Company's ability to develop and produce reserves.

Provisions of the Company's charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for the Company's common stock.

Provisions in the Company's certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which the Company is not the surviving company and may otherwise prevent or slow changes in the Company's board of directors and management. In addition, because the Company is incorporated in Delaware, it is governed by the provisions of Section 203 of the Delaware General Corporation Law. These provisions could discourage an acquisition of the Company or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for the Company's common stock.

The Company's sand mining operations are subject to operating risks that are often beyond the Company's control, and such risks may not be covered by insurance.

Ownership of industrial sand mining operations is subject to risks, many of which are beyond the Company's control. These risks include:

- unusual or unexpected geological formations or pressures;
- cave-ins, pit wall failures or rock falls;
- unanticipated ground, grade or water conditions;
- inclement or hazardous weather conditions, including flooding, and the physical impacts of climate change;
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environmental hazards, such as unauthorized spills, releases and discharges of wastes, vessel ruptures and emission of unpermitted levels of pollutants;

- changes in laws and regulations;
- inability to acquire or maintain necessary permits or mining or water rights;
- restrictions on blasting operations;
- inability to obtain necessary production equipment or replacement parts;
- reduction in the amount of water available for processing;
- technical difficulties or failures;

- labor disputes;
- late delivery of supplies;
- fires, explosions or other accidents; and
- facility interruptions or shutdowns in response to environmental regulatory actions.

Any of these risks could result in damage to, or destruction of, the Company's mining properties or production facilities, personal injury, environmental damage, delays in mining or processing, losses or possible legal liability. Not all of these risks are insurable, and the Company's insurance coverage contains limits, deductibles, exclusions and endorsements. The Company's insurance coverage may not be sufficient to meet its needs in the event of loss and any such loss may have a material adverse effect on the Company.

The Company's estimates of sand reserves and resource deposits are imprecise and actual reserves could be less than estimated.

The Company bases its sand reserve and resource estimates on engineering, economic and geological data assembled and analyzed by engineers and geologists, which are periodically reviewed by outside firms. However, commercial sand reserve estimates are necessarily imprecise and depend to some extent on statistical inferences drawn from available drilling data, which may prove unreliable. There are numerous uncertainties inherent in estimating quantities and qualities of commercial sand reserves and costs to mine recoverable reserves, including many factors beyond the Company's control. Estimates of economically recoverable commercial sand reserves necessarily depend on a number of factors and assumptions, all of which may vary considerably from actual results, such as:

- geological and mining conditions or effects from prior mining that may not be fully identified by available data or that may differ from experience;
- assumptions concerning future prices of commercial sand products, operating costs, mining technology improvements, development costs and reclamation costs; and
- assumptions concerning future effects of regulation, including the issuance of required permits and taxes by governmental agencies.

The Company's sand mining operations are subject to extensive environmental and occupational health and safety regulations that impose significant costs and potential liabilities.

The Company's sand mining operations are subject to a variety of federal, state and local environmental requirements affecting the mining and mineral processing industry, including, among others, those relating to employee health and safety, environmental permitting and licensing, air emissions and water discharges, GHG emissions, water pollution, waste management and disposal, remediation of soil and groundwater contamination, land use restrictions, reclamation and restoration of properties, hazardous materials and natural resources. Some environmental laws impose substantial penalties for noncompliance, and others, such as the CERCLA, impose strict, retroactive and joint and several liability for the remediation of releases of hazardous substances. Failure to properly handle, transport, store or dispose of hazardous materials or otherwise conduct the Company's sand mining operations in compliance with environmental laws could expose the Company to liability for governmental penalties, cleanup costs and civil or criminal liability associated with releases of such materials into the environment, damages to property or natural resources and other damages, as well as potentially impair the Company's ability to conduct its sand mining operations. In addition, environmental laws and regulations are subject to amendment, replacement or interpretation by more stringent and comprehensive legal requirements. The Company's continued compliance with existing or future laws and regulations could restrict the Company's ability to expand its facilities or extract mineral deposits or could require the Company to acquire costly equipment or to incur other significant expenses in connection with its sand mining operations, which restrictions or costs could have a material adverse effect on the Company's sand mining operations.

Any failure by the Company to comply with applicable environmental laws and regulations in connection with its sand mining operations may cause governmental authorities to take actions that could adversely affect the Company, including:

- issuance of administrative, civil and criminal penalties;
- denial, modification or revocation of permits or other authorizations;

- imposition of injunctive obligations or other limitations on the Company's operations, including interruptions or cessation of operations; and
- requirements to perform site investigatory, remedial or other corrective actions.

In addition to environmental regulation, the Company's sand mining operations are subject to laws and regulations relating to worker health and safety, including such matters as human exposure to crystalline silica dust. Several federal and state regulatory authorities, including the U.S. Mining Safety and Health Administration, may continue to propose changes in their regulations regarding workplace exposure to crystalline silica, such as permissible exposure limits and required controls and personal protective equipment.

The Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, which imposes stringent health and safety standards on numerous aspects of the Company's sand mining operations.

The Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. The Company's failure to comply with such standards, or changes in such standards or the interpretation or enforcement thereof, could have a material adverse effect on the Company's sand mining operations or otherwise impose significant restrictions on the Company's ability to conduct mineral extraction and processing operations.

The Company's sand mining operations are subject to extensive other regulations that impose significant costs and liabilities.

In addition to the environmental and occupational health and safety regulation discussed above, the Company's sand mining operations are also subject to extensive governmental regulation on matters such as permitting and licensing requirements, reclamation and restoration of mining properties after mining is completed, and the effects that mining have on groundwater quality and availability. Also, the Company's sand mining operations require numerous governmental, environmental, mining and other permits, water rights and approvals authorizing operations at each sand mining facility.

In order to obtain permits and renewals of permits in the future for its sand mining operations, the Company may be required to prepare and present data to governmental authorities pertaining to the effect that any such activities may have on the environment. Obtaining or renewing required permits may be delayed or prevented due to opposition by neighboring property owners, members of the public or other third parties and other factors beyond the Company's control. A decision by a governmental agency or other third party to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on the Company's sand mining operations at the affected facility. Current or future regulations could have a material adverse effect on the Company's sand mining operations and the Company may not be able to renew or obtain permits in the future.

The Company's sand mining operations and hydraulic fracturing may result in silica-related health issues and litigation that could have a material adverse effect on the Company.

The inhalation of respirable crystalline silica dust is associated with the lung disease silicosis. There is evidence of an association between crystalline silica exposure or silicosis and lung cancer and a possible association with other diseases, including immune system disorders, such as scleroderma. These health risks have been a significant issue confronting the commercial sand industry. The actual or perceived health risks of mining, processing and handling sand could materially and adversely affect the Company through the threat of product liability or personal injury lawsuits and increased scrutiny by federal, state and local regulatory authorities.

Premier Silica is named as a defendant, usually among many defendants, in numerous products liability lawsuits brought by or on behalf of current or former employees of Premier Silica's commercial customers alleging damages caused by silica exposure. As of December 31, 2014, Premier Silica was the subject of silica exposure claims from approximately 575 plaintiffs, the great majority of which claims have been inactive for many years due to the plaintiffs' failure to meet specific legal requirements to advance their claims. Almost all of the claims pending against Premier Silica arise out of the alleged use of Premier Silica's sand products in foundries or as an abrasive blast media and have been filed in the states of Texas and Missouri, although some cases have been brought in many other jurisdictions over the years.

It is possible that Premier Silica will have additional silica-related claims filed against it, including claims that allege silica exposure for periods for which there is not insurance coverage. In addition, it is possible that similar claims could be asserted arising out of the Company's other operations, including it hydraulic fracturing operations. Any pending or future claims or inadequacies of insurance coverage or contractual indemnification could have a material adverse effect on the Company's results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 2. PROPERTIES

Reserve Estimation Procedures and Audits

The information included in this Report about the Company's proved reserves as of December 31, 2014, 2013 and 2012 is based on evaluations prepared by the Company's engineers and (i) audited by Netherland, Sewell & Associates, Inc. ("NSAI"), with respect to the Company's major properties for all periods, and (ii) audited by Ryder Scott Company, L.P. ("RSC"), with respect to the Company's Oooguruk field properties in Alaska as of December 31, 2012. The Company has no oil and gas reserves from non-traditional sources. Additionally, the Company does not provide optional disclosure of probable or possible reserves.

Reserve estimation procedures. The Company has established internal controls over reserve estimation processes and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC and GAAP requirements. These controls include oversight of the reserves estimation reporting processes by Pioneer's Corporate Reserves Group ("Corporate Reserves"), and annual external audits of substantial portions of the Company's proved reserves by NSAI.

Individual asset teams are responsible for the day-to-day management of the oil and gas activities in each of the Company's Permian Basin, Rockies, Mid-Continent and South Texas asset areas (the "Asset Teams"). The Company's Asset Teams are each staffed with reservoir engineers and geoscientists who prepare reserve estimates at the end of each calendar quarter for the assets that they manage, using reservoir engineering information technology. There is shared oversight of the Asset Teams' reservoir engineers by the Asset Teams' managers and the Vice President of Corporate Reserves, each of whom is in turn subject to direct or indirect oversight by the Company's management committee ("MC"). The Company's MC is comprised of its Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and other Executive Vice Presidents. The Asset Teams' reserve estimates are reviewed by the Asset Team reservoir engineers before being submitted to Corporate Reserves for further review.

The reserve estimates are summarized in reserve reconciliations that quantify reserve changes since the previous year end as revisions of previous estimates, purchases of minerals-in-place, improved recovery, extensions and discoveries, production and sales of minerals-in-place. All reserve estimates, material assumptions and inputs used in reserve estimates and significant changes in reserve estimates are reviewed for engineering and financial appropriateness and compliance with SEC and GAAP standards by Corporate Reserves, in consultation with the Company's accounting and financial management personnel. Annually, the MC reviews the reserve estimates and any differences with the reserve auditors (for the portion of the reserves audited by NSAI or RSC) on a consolidated basis before these estimates are approved. The engineers and geoscientists who participate in the reserve estimation and disclosure process periodically attend training provided by external consultants and/or through internal Pioneer programs. Additionally, Corporate Reserves has prepared and maintains written policies and guidelines for the Asset Teams to reference on reserve estimation and preparation to promote objectivity in the preparation of the Company's reserve estimates and SEC and GAAP compliance in the reserve estimation and reporting process.

Proved reserves audits. The proved reserve audits performed by NSAI for the years ended December 31, 2014, 2013 and 2012, and by RSC for 2012, in the aggregate, represented 80 percent, 94 percent and 95 percent of the Company's year-end 2014, 2013 and 2012 proved reserves, respectively; and 91 percent, 92 percent and 99 percent of the Company's year-end 2014, 2013 and 2012 associated pre-tax present value of proved reserves discounted at ten percent, respectively.

NSAI follows the general principles set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers (the "SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. The SPE's definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been presented in conformity with the 2007 SPE publication entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information."
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The estimation of reserves is an imprecise science due to the many unknown geologic and reservoir factors that cannot be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by a company is reasonable.

- The methods and procedures used by a company, and the reserve information furnished by a company, must be reviewed in sufficient detail to permit the reserve auditor, in its professional judgment, to express an opinion as to the reasonableness of the reserve information. The auditing procedures require the reserve auditor to prepare their own estimates of reserve information for the audited properties.

In conjunction with the audit of the Company's proved reserves and associated pre-tax present value discounted at ten percent, Pioneer provided to NSAI its external and internal engineering and geoscience technical data and analyses. Following NSAI's review of that data, it had the option of honoring Pioneer's interpretations, or making its own interpretations. No data was withheld from NSAI. NSAI accepted without independent verification the accuracy and completeness of the historical information and data furnished by Pioneer with respect to ownership interest, oil and gas production, well test data, commodity prices, operating and development costs, and any agreements relating to current and future operations of the properties and sales of production. However, if in the course of its evaluations something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

In the course of its evaluations, NSAI prepared, for all of the audited properties, its own estimates of the Company's proved reserves and the pre-tax present values of such reserves discounted at ten percent. NSAI reviewed its audit differences with the Company, and, in a number of cases, held meetings with the Company to review additional reserves work performed by the Company's technical teams and any updated performance data related to the proved reserve differences. Such data was incorporated, as appropriate, by both parties into the proved reserve estimates. NSAI's estimates, including any adjustments resulting from additional data, of those proved reserves and the pre-tax present value of such reserves discounted at ten percent did not differ from Pioneer's estimates by more than ten percent in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of the Company's estimates were greater than those of the reserve auditors and some were less than the estimates of the reserve auditors. When such differences do not exceed ten percent in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present values of such reserves discounted at ten percent are reasonable and that its audit objectives have been met, NSAI will issue an unqualified audit opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analyses by the Company and the reserve auditors. At the conclusion of the audit process, it was NSAI's opinion, as set forth in its audit letter, which is included as an exhibit to this Report, that Pioneer's estimates of the Company's proved oil and gas reserves and associated pre-tax present values discounted at ten percent are, in the aggregate, reasonable and have been prepared in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE.

See "Item 1A. Risk Factors," "Critical Accounting Estimates" in "Item 7. Management's Discussion and Analysis and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" for additional discussions regarding proved reserves and their related cash flows.

Qualifications of proved reserves preparers and auditors. Corporate Reserves is staffed by petroleum engineers with extensive industry experience and is managed by the Vice President of Corporate Reserves, the technical person that is primarily responsible for overseeing the Company's reserves estimates. These individuals meet the professional qualifications of reserves estimators and reserves auditors as defined by the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information," promulgated by the SPE. The qualifications of the Vice President of Corporate Reserves include 37 years of experience as a petroleum engineer, with 30 years focused on reserves reporting for independent oil and gas companies, including Pioneer. His educational background includes an undergraduate degree in Chemical Engineering and a Masters of Business Administration degree in Finance. He is also a Chartered Financial Analyst Charterholder.

NSAI provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. The technical person primarily responsible for auditing the Company's reserves estimates has been a practicing consulting petroleum engineer at NSAI since 1983 and has over 36 years of practical experience in petroleum engineering, including over 34 years of experience in the estimation and evaluation of proved reserves. He graduated with a Bachelor of Science degree in Chemical Engineering in 1978 and meets or exceeds the education, training and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the board of directors of the SPE.

RSC provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. RSC was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. The technical person primarily responsible for auditing the Company's Alaska reserves estimates in 2012 was a practicing consulting petroleum engineer at RSC since 2000 with over 28 years of practical experience in petroleum engineering. He graduated with a Bachelor of Science degree in Petroleum Engineering and a Master of Business Administration degree and at the time of the reserves audit he met or exceeded the education, training and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the board of directors of the SPE.

Technologies used in proved reserves estimates. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped proved reserves only if an ability and intent has been established to drill the reserves within five years, unless specific circumstances justify a longer time period.

In the context of reserves estimations, reasonable certainty means a high degree of confidence that the quantities will be recovered and reliable technology means a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonable certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating proved reserves, the Company uses several different traditional methods such as performance-based methods, volumetric-based methods and analogy with similar properties. In addition, the Company utilizes additional technical analysis such as seismic interpretation, wireline formation tests, geophysical logs and core data to provide incremental support for more complex reservoirs. Information from this incremental support is combined with the traditional technologies outlined above to enhance the certainty of the Company's proved reserve estimates.

Proved Reserves

As of December 31, 2014, 2013 and 2012, the Company's oil and gas proved reserves are located entirely in the United States. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional details of the Company's discontinued operations. The following table provides information regarding the Company's proved reserves as of December 31, 2014, 2013 and 2012:

	Summary of Oil and Gas Reserves as of Fiscal Year-End Based on Average Fiscal-Year Prices					
	Reserve Volumes					
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	%	
December 31, 2014:						
Developed	267,193	130,206	1,486,289	645,113	81	%
Undeveloped	84,891	39,038	182,583	154,360	19	%
Total proved reserves	352,084	169,244	1,668,872	799,473	100	%
December 31, 2013:						
Developed	256,638	148,161	1,703,667	688,743	81	%
Undeveloped	85,467	37,261	202,674	156,507	19	%
Total proved reserves	342,105	185,422	1,906,341	845,250	100	%
Less proved reserves associated with discontinued operations	24,128	27,733	287,606	99,795	12	%
Total proved reserves associated with continuing operations	317,977	157,689	1,618,735	745,455	88	%
December 31, 2012:						
Developed	230,700	134,637	1,605,209	632,872	58	%
Undeveloped	256,138	97,939	592,271	452,789	42	%
Total proved reserves	486,838	232,576	2,197,480	1,085,661	100	%
Less proved reserves associated with discontinued operations	48,274	42,331	383,931	154,594	14	%
Total proved reserves associated with continuing operations	438,564	190,245	1,813,549	931,067	86	%

(a) Total proved gas reserves contain 191,932 MMcf, 240,093 MMcf and 280,344 MMcf of gas that the Company expected to be produced and used as field fuel (primarily for compressors) before the gas is delivered to a sales point, as of December 31, 2014, 2013 and 2012, respectively.

The Company's Standardized Measure of total proved reserves as of December 31, 2014 was $7.8 billion, including $6.4 billion and $1.4 billion related to proved developed and proved undeveloped reserves, respectively. The Company's Standardized Measure of total proved reserves as of December 31, 2013 was $7.3 billion, including $6.3 billion and $1.0 billion related to proved developed and proved undeveloped reserves, respectively. The Company's Standardized Measure of total proved reserves as of December 31, 2012 was $6.4 billion, including $5.0 billion and $1.4 billion related to proved developed and proved undeveloped reserves, respectively.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

See the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" for additional details of the estimated quantities of the Company's proved reserves, including explanations for material changes in proved developed and proved undeveloped reserves.

Description of Properties

The following tables summarize the Company's development and exploration/extension drilling activities during 2014:

	Development Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Wells Sold	Ending Wells In Progress
Permian Basin	59	257	271	4	41
South Texas—Eagle Ford Shale	16	34	37	—	13
Total continuing operations	75	291	308	4	54
Barnett Shale	1	—	1	—	—
Alaska	4	1	—	5	—
Total including discontinued operations	80	292	309	9	54

	Exploration/Extension Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Wells Sold	Ending Wells In Progress
Permian Basin	31	228	183	—	1	75
South Texas—Eagle Ford Shale	24	93	87	—	—	30
South Texas—Other	—	8	8	—	—	—
Other	3	3	—	5	—	1
Total continuing operations	58	332	278	5	1	106
Barnett Shale	17	42	52	—	7	—
Alaska	2	—	—	—	2	—
Total including discontinued operations	77	374	330	5	10	106

The following table summarizes the Company's average daily oil, NGL, gas and total production by asset area during 2014:

	Oil (Bbls)	NGLs (Bbls)	Gas (Mcf) (a)	Total (BOE)
Permian Basin	64,984	20,873	83,664	99,801
South Texas—Eagle Ford Shale	17,802	13,530	89,679	46,279
Raton Basin	—	—	124,310	20,718
West Panhandle	2,865	4,140	14,188	9,370
South Texas—Other	1,379	101	27,435	6,052
Other	4	2	65	17
Total continuing operations	87,034	38,646	339,341	182,237
Barnett Shale	1,604	2,867	21,453	8,047
Hugoton	—	1,668	16,428	4,405
Alaska	1,001	—	—	1,001
Total including discontinued operations	89,639	43,181	377,222	195,690

(a) Gas production excludes gas produced and used as field fuel.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

The following table summarizes the Company's costs incurred by asset area during 2014:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in millions)					
Permian Basin	$14	$78	$1,409	$1,194	$7	$2,702
South Texas—Eagle Ford Shale	—	—	348	219	1	568
Raton Basin	—	—	3	24	(10)	17
West Panhandle	—	—	2	11	2	15
South Texas—Other	—	—	19	12	3	34
Other	—	2	30	—	—	32
Total continuing operations	$14	$80	$1,811	$1,460	$3	$3,368
Barnett Shale	5	5	128	22	—	160
Hugoton	—	—	2	1	—	3
Alaska	—	—	(1)	48 (a)	4	51
Total including discontinued operations	$19	$85	$1,940	$1,531	$7	$3,582

(a) Includes $2 million of capitalized interest associated with the Oooguruk development project prior to its divestiture.

Permian Basin

The Spraberry field was discovered in 1949, encompasses eight counties in West Texas and the Company believes it is the largest oil field in the United States. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from six formations, the upper and lower Spraberry, the Dean, the Wolfcamp, the Strawn and the Atoka, at depths ranging from 6,700 feet to 11,300 feet. The Company believes that it has significant resource potential within its Spraberry and Wolfcamp formation acreage, based on its extensive geologic data covering the Spraberry and Wolfcamp A, B, C and D intervals and its drilling results to date. The Company expects to improve the incremental recovery rates in the Spraberry field through horizontal drilling while containing operating expenses and drilling costs through economies of scale and vertical integration of field services.

During 2014, the Company drilled 454 wells in the Spraberry field and its total acreage position now approximates 785,000 gross acres (692,000 net acres). During 2014, the Company placed on production 97 horizontal wells in the northern portion of the play, 113 horizontal wells in the southern portion of the play, where the Company has its joint venture with Sinochem, and 262 vertical wells. Three-well pads were utilized to drill most of the horizontal wells in the 2014 program. In the northern portion of the play, approximately 80 percent of the wells placed on production were Wolfcamp A, B and D interval wells and the remaining 20 percent were Spraberry Shale wells (Lower Spraberry Shale, Jo Mill Shale and Middle Spraberry Shale). In the southern portion of the play, approximately two-thirds of the wells placed on production were Wolfcamp B interval wells, with the remainder being a mix of Wolfcamp A, C and D interval wells.

The Company continued to shift its drilling activity in the Spraberry field from vertical drilling to horizontal drilling during 2014. The Company believes that replacing vertical drilling with horizontal drilling will enhance ultimate resource recoveries and improve rates of return per dollar invested. As a result, Pioneer no longer expects to drill any additional vertical locations in the Spraberry field in 2015 and has extended leases with continuous drilling obligations to allow the Company to drill those locations in the future with higher returning horizontal wells.

As a result of the significant decrease in oil prices, the Company is reducing its rig count for 2015 and expects to be at its planned 10 rig drilling program in the Spraberry field by the end of February 2015, all of which are drilling horizontal wells. During 2015, the Company expects to drill approximately four vertical wells and 105 horizontal wells (60 horizontal wells in the northern portion of the play and 45 horizontal wells in the southern portion of the play), with the horizontal wells being predominantly drilled in the Wolfcamp B horizon. The Company expects to spend $1.17 billion of drilling capital in the Spraberry field during 2015.

In January 2013, the Company signed an agreement with Sinochem, an unaffiliated third party, to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for consideration of $1.8 billion. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $624 million, resulting in a 2013 gain of $181 million related to the unproved property interests conveyed to Sinochem. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play. At December 31, 2014, the unused carry balance totaled $575 million. Associated with the closing of the joint venture transaction, the Company conveyed a 40 percent interest in the producing horizontal Wolfcamp Shale wells in the joint venture area.

Sinochem also elected to participate in certain vertical wells that were drilled in the joint interest area after the December 1, 2012 effective date and received its share of production and costs from the Wolfcamp and deeper horizons based on the reserve contribution from the Wolfcamp and deeper intervals relative to reserves from all completed intervals. Pioneer's and Sinochem's participation in vertical wells is based on each party's interest without any drilling carry applied. Pioneer retained 100 percent of its vertical production in the joint interest area for wells drilled before the December 1, 2012 effective date. Pioneer also retained its current working interests in all horizons shallower than the Wolfcamp horizon and continues as operator of the properties in the joint interest area.

The Company continues to benefit from its integrated services to control drilling and operating costs and support the execution of its drilling and production activities in the Spraberry field. The Company is currently utilizing six Company-owned fracture stimulation fleets totaling approximately 250,000 horsepower in the Spraberry field. To support its operations, the Company also owns other field service equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In addition, Premier Silica (the Company's wholly-owned sand mining subsidiary) is supplying brown sand for proppant, which is being used to fracture stimulate vertical and horizontal wells in the Spraberry and Wolfcamp Shale intervals.

The Company's long-term growth plan continues to be focused on optimizing the development of the field and identifying the future requirements for water, field infrastructure, gas processing, sand, pipeline takeaway, oilfield services, tubulars, electricity, systems, buildings and roads. However, much of the Company's front-end loaded infrastructure plans, which were expected to provide significant future cost savings and support the Company's long-term growth plan in the Spraberry/Wolfcamp area, have been deferred given the significant decline in oil prices. The Company plans to re-evaluate its infrastructure plans for a field-wide water distribution network, additional gas processing facilities, continued build-out of horizontal tank batteries and expansion of Premier Silica's Brady sand mine when oil prices recover and/or costs improve.

South Texas Eagle Ford Shale

The Company's drilling activities in the South Texas area during 2014 continued to be primarily focused on development of Pioneer's substantial acreage position in the Eagle Ford Shale play. The 2014 drilling program was focused on liquids-rich drilling, with no wells drilled in its dry gas acreage. During 2014, the Company also received confirmation from the U.S. Department of Commerce that condensate processed through distillation units, such as those located at several of Pioneer's Eagle Ford Shale central gathering plants in South Texas, is a petroleum product that may be exported without a license.

The Company completed 124 horizontal Eagle Ford Shale wells during 2014, all of which were successful, with average lateral lengths of 5,719 feet and, on average, 20-stage fracture stimulations. The Company placed 50 upper target Eagle Ford Shale wells on production and estimates that approximately 25 percent of the Company's acreage is prospective for this interval in the Eagle Ford Shale play. The Company plans to spend $390 million of capital in 2015 to drill approximately 83 Eagle Ford Shale wells. The Company is operating two Pioneer-owned fracture stimulation fleets in the play.

In 2013, the Company added approximately 300 drilling locations in the liquids-rich area of the play as a result of downspacing from 1,000 feet between wells (120-acre spacing) to 500 feet (60-acre spacing) between wells. Further downspacing and staggered testing to a range of 175 feet to 300 feet between staggered wells is underway in the liquids-rich areas where the 500-foot spacing was successful. Some areas will include testing of the Lower Eagle Ford Shale interval only, while others will include a combination of lower and upper targets within the Eagle Ford Shale. Results from the downspacing and staggered tests in the Eagle Ford Shale continue to be encouraging.

The Company's drilling operations in the Eagle Ford Shale continue to focus on improving drilling efficiencies. During 2014, most Eagle Ford Shale wells were drilled utilizing three-well and four-well pads. Pad drilling saves the

Company a significant amount of capital costs per well, as compared to drilling single-well locations.

The Company owns a 50.1 percent member interest in EFS Midstream, an entity formed by the Company to own and operate gas and liquids gathering, treating and transportation assets in the Eagle Ford Shale play. The Company does not have control of EFS Midstream and accounts for its investment in EFS Midstream under the equity method of accounting for investments in unconsolidated affiliates. EFS Midstream is obligated to construct midstream assets in the Eagle Ford Shale area. The majority of the construction of the midstream assets has been completed. Eleven of the 13 planned central gathering plants were completed as of December 31, 2014. EFS Midstream is providing gathering, treating and transportation services for the Company during a 20-year contractual term.

During November 2014, the Company announced that it is pursuing the divestment of its 50.1 percent share of EFS Midstream. The Company is marketing its equity investment in EFS Midstream and no assurance can be given that a sale will be completed in accordance with the Company's plans or on terms and at a price acceptable to the Company.

Raton Basin

The Raton Basin properties are located in the southeast portion of Colorado. The Company owns approximately 194,000 gross acres (174,000 net acres) in the center of the Raton Basin and produces CBM gas from the coal seams in the Vermejo and Raton formations from approximately 2,300 wells. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the impairment charge recorded during 2013 to reduce the carrying value of the Company's gas properties in the Raton field.

West Panhandle

The West Panhandle properties are located in the panhandle region of Texas. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas has an average energy content of 1,400 Btu and is produced from approximately 700 wells on more than 246,000 gross acres (239,000 net acres) covering over 375 square miles. The Company controls 100 percent of the wells, production equipment, gathering system and the Fain gas processing plant for the field. As this field is characterized by very low reservoir pressure, Pioneer continually works to improve compressor and gathering system efficiency.

Divestitures Recorded as Discontinued Operations

Domestic. The Company completed the divestitures of its net assets in the Hugoton field in southwest Kansas, its net assets in the Barnett Shale field in North Texas and 100 percent of the capital stock in Pioneer Alaska in September 2014, September 2014 and April 2014, respectively.

The Company has reflected its Hugoton, Barnett Shale and Pioneer Alaska results of operations as discontinued operations in the accompanying consolidated statements of operations. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's divestitures of its Hugoton and Barnett Shale field assets and Pioneer Alaska.

International. During August 2012, the Company completed the sale of Pioneer South Africa to an unaffiliated third party. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the sale of Pioneer South Africa. As a result of this sale, the Company no longer has operations outside the United States.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2014, 2013 and 2012. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The price that the Company receives for the oil and gas it produces is largely a function of market supply and demand. Demand is affected by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or gas can result in substantial price volatility. Historically, commodity prices have been volatile and the Company expects that volatility to continue in the future. If the recent decline in oil and gas prices were to persist, or if such prices were to decline further, or if the Company experienced poor drilling results, it could have a material adverse effect on the Company's financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and the Company's ability to access capital markets.

The following tables set forth production, price and cost data with respect to the Company's properties for 2014, 2013 and 2012. These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not match the proved reserve volume tables in the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" because field fuel volumes are included in the proved reserve volume tables.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2014					
	Included in Continuing Operations				Included in Discontinued Operations	Total
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	
Production information:						
Annual sales volumes:						
Oil (MBbls)	23,701	6,498	—	31,767	951	32,718
NGLs (MBbls)	7,504	4,939	—	14,106	1,655	15,761
Gas (MMcf)	29,608	32,733	45,373	123,860	13,826	137,686
Total (MBOE)	36,139	16,892	7,562	66,516	4,911	71,427
Average daily sales volumes:						
Oil (Bbls)	64,935	17,802	—	87,034	2,605	89,639
NGLs (Bbls)	20,558	13,530	—	38,646	4,535	43,181
Gas (Mcf)	81,117	89,679	124,310	339,341	37,881	377,222
Total (BOE)	99,012	46,279	20,718	182,237	13,453	195,690
Average prices:						
Oil (per Bbl)	$86.51	$81.84	$—	$85.29	$93.10	$85.51
NGL (per Bbl)	$27.06	$25.49	$—	$27.06	$30.30	$27.40
Gas (per Mcf)	$3.81	$4.35	$4.05	$4.10	$4.30	$4.12
Revenue (per BOE)	$65.48	$47.36	$24.30	$54.11	$40.36	$53.17
Average costs (per BOE):						
Production costs:						
Lease operating	$11.42	$2.68	$6.72	$8.27	$8.54	$8.29
Third-party transportation charges	0.40	3.88	3.41	1.68	2.33	1.73
Net natural gas plant/gathering	(1.23)	0.03	2.25	(0.20)	0.88	(0.12)
Workover	0.94	0.33	—	0.65	0.40	0.64
Total	$11.53	$6.92	$12.38	$10.40	$12.15	$10.54
Production and ad valorem taxes:						
Ad valorem	$1.43	$0.83	$0.73	$1.13	$1.25	$1.14
Production	3.18	1.22	0.36	2.18	1.11	2.11
Total	$4.61	$2.05	$1.09	$3.31	$2.36	$3.25
Depletion expense	$20.41	$11.49	$4.48	$15.19	$2.10	$14.29

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2013					
	Included in Continuing Operations				Included in Discontinued Operations	
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	Total
Production information:						
Annual sales volumes:						
Oil (MBbls)	19,176	5,014	—	25,377	2,078	27,455
NGLs (MBbls)	5,410	3,804	—	10,917	2,082	12,999
Gas (MMcf)	24,679	29,367	49,126	120,816	18,062	138,878
Total (MBOE)	28,699	13,712	8,188	56,431	7,170	63,601
Average daily sales volumes:						
Oil (Bbls)	52,537	13,737	—	69,527	5,693	75,220
NGLs (Bbls)	14,822	10,421	—	29,910	5,705	35,615
Gas (Mcf)	67,614	80,458	134,591	331,003	49,484	380,487
Total (BOE)	78,627	37,568	22,432	154,604	19,645	174,249
Average prices:						
Oil (per Bbl)	$93.30	$91.74	$—	$92.62	$98.81	$93.09
NGL (per Bbl)	$30.34	$26.72	$—	$29.99	$28.76	$29.79
Gas (per Mcf)	$3.23	$3.63	$3.27	$3.39	$3.53	$3.41
Revenue (per BOE)	$70.84	$48.73	$19.61	$54.71	$45.88	$53.71
Average costs (per BOE):						
Production costs:						
Lease operating	$11.38	$3.23	$6.25	$8.19	$11.64	$8.58
Third-party transportation charges	0.24	3.86	3.02	1.59	1.43	1.57
Net natural gas plant/gathering	(1.11)	0.01	1.90	(0.16)	1.45	0.02
Workover	1.45	0.20	—	0.80	1.76	0.91
Total	$11.96	$7.30	$11.17	$10.42	$16.28	$11.08
Production and ad valorem taxes:						
Ad valorem	$1.70	$0.65	$0.42	$1.15	$2.01	$1.25
Production	3.45	1.31	0.35	2.25	0.67	2.07
Total	$5.15	$1.96	$0.77	$3.40	$2.68	$3.32
Depletion expense	$18.47	$8.80	$18.97	$15.05	$16.47	$15.20

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2012						
	Included in Continuing Operations				Included in Discontinued Operations		
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	South Africa	Total
Production information:							
Annual sales volumes:							
Oil (MBbls)	16,096	3,613	—	20,922	2,006	157	23,085
NGLs (MBbls)	4,451	2,683	—	8,988	1,925	—	10,913
Gas (MMcf)	21,345	23,182	54,822	120,497	17,986	3,784	142,267
Total (MBOE)	24,104	10,160	9,137	49,993	6,928	787	57,708
Average daily sales volumes:							
Oil (Bbls)	43,978	9,871	—	57,165	5,480	428	63,073
NGLs (Bbls)	12,160	7,332	—	24,557	5,259	—	29,816
Gas (Mcf)	58,319	63,338	149,787	329,228	49,141	10,340	388,709
Total (BOE)	65,858	27,759	24,965	136,593	18,929	2,151	157,673
Average prices, including hedge results and amortization of deferred VPP revenue (a):							
Oil (per Bbl)	$90.57	$93.84	$—	$90.67	$93.20	$108.62	$91.01
NGL (per Bbl)	$32.23	$31.81	$—	$34.08	$32.22	$—	$33.75
Gas (per Mcf)	$2.58	$2.81	$2.41	$2.56	$2.84	$8.50	$2.75
Revenue (per BOE)	$68.72	$48.18	$14.48	$50.24	$43.31	$62.48	$49.57
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):							
Oil (per Bbl)	$87.95	$93.84	$—	$88.81	$93.20	$108.62	$89.32
NGL (per Bbl)	$32.23	$31.81	$—	$34.08	$32.22	$—	$33.75
Gas (per Mcf)	$2.58	$2.81	$2.41	$2.56	$2.84	$8.50	$2.75
Revenue (per BOE)	$66.97	$48.18	$14.48	$49.46	$43.31	$62.48	$48.90
Average costs (per BOE):							
Production costs:							
Lease operating	$11.33	$3.21	$6.47	$8.15	$11.36	$2.86	$8.46
Third-party transportation charges	0.17	3.00	3.12	1.33	1.15	—	1.29
Net natural gas plant/gathering	(0.49)	—	1.82	0.27	1.93	—	0.47
Workover	1.71	0.08	—	0.87	0.69	—	0.84
Total	$12.72	$6.29	$11.41	$10.62	$15.13	$2.86	$11.06
Production and ad valorem taxes:							
Ad valorem	$1.78	$0.71	$0.17	$1.13	$2.16	$—	$1.24
Production	3.47	2.00	0.11	2.25	0.53	—	2.01
Total	$5.25	$2.71	$0.28	$3.38	$2.69	$—	$3.25
Depletion expense	$15.58	$5.51	$19.52	$13.14	$17.03	$—	$13.42

(a) The Company recorded the amortization of deferred VPP revenue at a field level but did not record the results of its hedging activities at a field level. As of December 31, 2012, the Company had no further obligation to deliver oil under the VPP and did not have any hedging activities.

Table of Contents

Productive wells. Productive wells consist of producing wells and wells capable of production, including shut-in wells and gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. One or more completions in the same well bore are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2014:

PRODUCTIVE WELLS

Gross Productive Wells			Net Productive Wells		
Oil	Gas	Total	Oil	Gas	Total
7,132	3,706	10,838	6,318	3,351	9,669

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2014:

LEASEHOLD ACREAGE

Developed Acreage		Undeveloped Acreage		Royalty Acreage
Gross Acres	Net Acres	Gross Acres	Net Acres	
1,321,885	1,114,056	1,020,417	753,603	244,615

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2014:

	Acres Expiring (a)	
	Gross	Net
2015	94,708	70,523
2016	711,401	501,741
2017	105,736	76,772
2018	78,328	77,761
2019	4,421	3,595
Thereafter	25,823	23,211
Total	1,020,417	753,603

(a) Acres expiring are based on contractual lease maturities.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

Drilling and other exploratory and development activities. The following table sets forth the number of gross and net wells drilled by the Company during 2014, 2013 and 2012 that were productive or dry holes. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry holes.

DRILLING ACTIVITIES

	Gross Wells			Net Wells		
	Year Ended December 31,			Year Ended December 31,		
	2014	2013	2012	2014	2013	2012
Productive wells:						
Development	309	444	659	258	382	595
Exploratory	330	244	223	239	164	144
Dry holes:						
Development	—	1	10	—	1	6
Exploratory	5	9	6	5	6	6
Total	644	698	898	502	553	751
Success ratio (a)	99 %	99 %	98 %	99 %	99 %	98 %

(a) Represents the ratio of those wells that were successfully completed as producing wells or wells capable of producing to total wells drilled and evaluated.

Present activities. The following table sets forth information about the Company's wells that were in process of being drilled as of December 31, 2014:

	Gross Wells	Net Wells
Development	54	39
Exploratory	106	76
Total	160	115

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding legal proceedings involving the Company.

ITEM 4. MINE SAFETY DISCLOSURES

The Company's sand mines are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report filed on Form 10-K.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock is listed and traded on the NYSE under the symbol "PXD." The Company's board of directors (the "Board") declared dividends to the holders of the Company's common stock of $0.04 per share during each of the first and third quarters of the years ended December 31, 2014 and 2013. The Board intends to consider the payment of dividends to the holders of the Company's common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board and will depend on, among other things, the Company's earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the Board deems relevant.

The following table sets forth quarterly high and low prices of the Company's common stock and dividends declared per share for the years ended December 31, 2014 and 2013:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2014			
Fourth quarter	$199.56	$127.31	$—
Third quarter	$234.60	$193.03	$0.04
Second quarter	$234.20	$177.53	$—
First quarter	$205.89	$163.90	$0.04
Year ended December 31, 2013			
Fourth quarter	$227.42	$172.60	$—
Third quarter	$190.15	$146.19	$0.04
Second quarter	$157.81	$109.19	$—
First quarter	$133.68	$107.29	$0.04

On February 13, 2015, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $157.85 per share.

As of February 13, 2015, the Company's common stock was held by 12,827 holders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of its common stock during the three months ended December 31, 2014:

Period	Total Number of Shares (or Units) Purchased (a)	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs
October 2014	965	$181.31	—	—
November 2014	55	$179.63	—	—
December 2014	2,977	$148.07	—	—
Total	3,997	$156.53	—	$ —

(a) Consists of shares purchased from employees in order for the employees to satisfy tax withholding payments related to share-based awards that vested during the period.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data of the Company as of and for each of the five years ended December 31, 2014 should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues	$3,599	$3,088	$2,512	$1,985	$1,432
Total revenues and other income (a)	$5,055	$3,652	$3,009	$2,418	$2,047
Total costs and expenses (a)(b)	$3,458	$4,226	$2,177	$1,863	$1,277
Income (loss) from continuing operations	$1,041	$(361)	$544	$380	$514
Income (loss) from discontinued operations, net of tax (c)	$(111)	$(438)	$(301)	$501	$132
Net income (loss) attributable to common stockholders	$930	$(838)	$192	$834	$605
Income (loss) from continuing operations attributable to common stockholders per share:					
Basic	$7.17	$(2.94)	$3.99	$2.80	$4.02
Diluted	$7.15	$(2.94)	$3.88	$2.74	$3.97
Net income (loss) attributable to common stockholders per share:					
Basic	$6.40	$(6.16)	$1.54	$7.01	$5.14
Diluted	$6.38	$(6.16)	$1.50	$6.88	$5.08
Dividends declared per share	$0.08	$0.08	$0.08	$0.08	$0.08
Balance Sheet Data (as of December 31):					
Total assets	$14,926	$12,294	$13,069	$11,447	$9,679
Long-term obligations	$4,757	$4,429	$6,167	$4,727	$4,684
Total stockholders' equity	$8,589	$6,615	$5,867	$5,651	$4,226

(a) The Company recognized revenues from the sale of purchased oil and gas of $726 million, $334 million and $122 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Company also recognized expenses related to purchased oil and gas of $703 million, $336 million and $120 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to satisfy unused pipeline capacity commitments and to diversify a portion of the Company's WTI oil sales to a Gulf Coast market price. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's revenues and expenses from these transactions.

(b) During 2013 and 2011, the Company recognized impairment charges of $1.5 billion related to dry gas properties in the Raton field and $354 million related to its Edwards and Austin Chalk net assets in South Texas, respectively. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's impairment charges.

(c) The Company recognized impairment charges of (i) $305 million attributable to the Hugoton assets, Pioneer Alaska and the Barnett Shale assets in 2014, (ii) $729 million attributable to Pioneer Alaska and the Barnett Shale assets in 2013 and (iii) $533 million attributable to the Barnett Shale assets in 2012. During 2011, the Company recognized a gain on the sale of Pioneer Tunisia of $645 million. The results of these operations are classified as discontinued operations in accordance with GAAP. See Notes C and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's discontinued operations and related impairment charges.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Financial and Operating Performance

Pioneer's financial and operating performance for 2014 included the following highlights:

- Net income attributable to common stockholders was $930 million ($6.38 per diluted share) for the year ended December 31, 2014, as compared to net loss attributable to common stockholders of $838 million ($6.16 per diluted share) in 2013. The $1.8 billion increase in net income attributable to common stockholders is primarily comprised of a $1.4 billion increase in income from continuing operations and a $327 million decrease in loss from discontinued operations, net of tax.

The primary components of the increase in net income from continuing operations include:

- a $708 million increase in net derivative gains, primarily as a result of changes in forward commodity prices and changes in the Company's portfolio of derivatives;
- a $511 million increase in oil and gas revenues as a result of an 18 percent increase in total sales volumes, partially offset by a one percent decrease in average commodity prices received per BOE;
- a $1.5 billion decrease in impairment charges related to the 2013 impairment recorded to reduce the carrying value of the Company's Raton gas field assets based on reductions in management's long-term gas price outlook (see Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and "Results of Operations" below); and
- a $48 million decrease in other expense, primarily due to decreases in impairment of inventory and other assets; partially offset by
- a $769 million increase in income taxes due to the increase in income from continuing operations before income taxes;
- a $200 million decrease in gain on disposition of assets, primarily due to the gain recorded in 2013 on the Company's sale of a 40 percent interest in the Company's horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas to Sinochem;
- a $158 million increase in DD&A expense, primarily attributable to the 18 percent increase in sales volumes, partially offset by the aforementioned impairment of proved properties in the Raton field during the fourth quarter of 2013, which reduced the Raton field's carrying value by $1.5 billion;
- a $133 million increase in total oil and gas production costs and production and ad valorem taxes, primarily due to an 18 percent increase in sales volumes; and
- a $37 million increase in general and administrative expenses primarily due to increases in contract labor and information technology related to process improvement initiatives and an increase in employee benefit costs.

The primary components of the decrease in the loss from discontinued operations, net of tax, include:

- a $424 million decrease in impairment provisions associated with the sales of Pioneer Alaska and the Company's Barnett Shale field and Hugoton field assets ($305 million) as compared to the 2013 impairments of Pioneer Alaska and the Company's Barnett Shale field assets included in discontinued operations ($729 million); partially offset by
- a $138 million decrease in revenues and other income, primarily due to the sale of Pioneer Alaska in April 2014 and the Hugoton field assets and Barnett Shale field assets in September 2014.
- Daily sales volumes from continuing operations increased on a BOE basis by 18 percent to 182,237 BOEPD during 2014, as compared to 154,604 BOEPD during 2013, primarily due to the success of the Company's drilling programs;
- Average reported oil and NGL prices from continuing operations decreased during 2014 to $85.29 per Bbl and $27.06 per Bbl, respectively, as compared to respective average reported prices of $92.62 per Bbl and $29.99 per Bbl during 2013. Average reported gas prices from continuing operations increased during 2014 to $4.10 per Mcf, as compared to an average reported price of $3.39 per Mcf during 2013;
- Net cash provided by operating activities increased by 10 percent to $2.4 billion for 2014, as compared to $2.1 billion during 2013, primarily due to the increases in oil, NGL and gas sales volumes, partially offset by a $65 million decrease in cash receipts on settled derivative instruments; and
-

As of December 31, 2014, the Company's net debt to book capitalization declined to 16 percent, as compared to 25 percent as of December 31, 2013, primarily due to (i) the April 2014 completion of the sale of Pioneer Alaska for $267 million of cash proceeds, (ii) the September 2014 completion of the sales of the Company's Hugoton and Barnett Shale net assets for cash proceeds of $328 million and $150 million, respectively, and (iii) the November 2014 issuance of 5.75 million shares of the Company's common stock for $980 million of cash proceeds, net of associated underwriting and offering expenses.

Table of Contents

Significant Events

Commodity prices. North American oil prices had been fairly stable during the past three years despite the significant increase in United States oil production from unconventional shale plays. The growth in North American oil production had been offset by reduced oil imports, keeping supply and demand fairly balanced in the United States. On an international level, the geopolitical factors negatively impacting international oil supplies were offset by the decline in United States imports, resulting in generally stable world oil prices. During the second half of 2014, however, as United States production continued to surge, worldwide demand was sluggish, reflecting the decline in the Chinese growth rate, the lingering recession in Europe and weaker economic performance in other regions, resulting in a worldwide oversupply and oil price weakness. During the fourth quarter of 2014, members of the OPEC decided to maintain production quotas at current levels despite production outpacing demand. This caused oil prices, which had already been declining, to decrease significantly in December 2014. The market oversupply of oil is expected to continue in 2015, with oil prices expected to remain under pressure. The growth of unconventional shale drilling has also substantially increased the supply of NGLs, resulting in a significant decline in NGL component prices as the supply of such products has grown. While more export facilities have been built and NGL exports are increasing, the overall United States demand for NGL products has not kept pace with the supply of such products; consequently, prices for NGL products have generally declined over the past three years. North American gas prices have remained volatile and they trended lower from 2009 through 2012, but improved steadily throughout 2013 and 2014 before dropping significantly in the fourth quarter of 2014. The decline in North American gas prices from 2009 through 2012 was primarily a result of significant discoveries of gas and associated gas reserves in United States gas, oil and liquid-rich shale plays, combined with the warmer than normal winters, which resulted in gas storage levels being at historically high levels, and minimal economic demand growth in the United States. The increases in gas prices during the latter part of 2013 and the majority of 2014 were primarily related to reduced drilling activity in gas shale plays and demand increases as a result of colder late 2013 and early 2014 winter weather, which reduced storage levels. The recent gas price decrease during the fourth quarter of 2014 reflects expectations for a warmer than normal winter, which is expected to result in gas storage levels being higher than normal at the end of the winter draw season and an expectation that there will be an oversupply of gas during 2015.

These circumstances have led to a dramatic decrease in drilling activity in the industry and have reduced the demand for drilling rigs, oilfield supplies, drill pipe and utilities, for which prices had reached very high levels during a period of high utilization in 2014. Although these costs have begun to decline, their declines significantly lag behind the declines in oil, NGL and gas prices. As a result of these circumstances, the Company experienced significant operating margin deterioration during the fourth quarter of 2014 and such deterioration has continued into 2015. The duration and magnitude of the commodity price declines and the timing and amount of cost reductions cannot be predicted.

Low price environment initiatives. As a result of the significant drop in commodity prices, the Company has implemented initiatives to reduce capital spending, operating costs and general and administrative expenses to minimize spending in excess of estimated cash flows for 2015 and to maintain significant financial flexibility. This plan includes reducing drilling and infrastructure development activities until margins improve as a result of (i) increased commodity prices and/or (ii) decreased well costs.

Pioneer is in the process of reducing its rig activity to 16 horizontal rigs drilling by the end of February 2015. The Company is continuing to work with drilling and service providers to reduce drilling and completion costs. To date, Pioneer has achieved reductions of approximately ten percent in drilling and completion costs, as compared to 2014 average well costs, and is targeting an additional ten percent reduction. Rigs have been terminated or stacked in the Spraberry/Wolfcamp and the Eagle Ford Shale areas. The Company's asset teams are also implementing initiatives to reduce controllable production costs, including costs associated with fuel surcharges, electricity supply, water disposal and compression rental.

In addition to the cost initiatives, the Company is also implementing the following initiatives to gain operating efficiencies:

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completion optimization in the Spraberry/Wolfcamp area where the testing of increased clusters per stage and optimized fluid chemistry and proppant concentrations continue to be encouraging;

- modified three-string and two-string casing design in the Upper Wolfcamp B and Wolfcamp A intervals; and
- dissolvable plug technologies in the Spraberry/Wolfcamp and Eagle Ford Shale areas to reduce or eliminate coil tubing drillouts after fracture stimulations.

In 2015, the Company expects capital spending for drilling operations to total $1.6 billion (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical general and administrative costs). Approximately 75 percent of this amount is for horizontal drilling, primarily in the Spraberry/Wolfcamp and Eagle Ford Shale areas. The Company also expects to spend $250 million on other property and equipment in 2015, principally related to water infrastructure, vertical integration and facilities.

First Quarter 2015 Outlook

Based on current estimates, the Company expects that first quarter 2015 production will average 192,000 to 197,000 BOEPD. First quarter guidance reflects an estimated production loss of 3,000 BOEPD in the Spraberry/Wolfcamp area due heavy icing and low temperatures during January that resulted in extensive power outages, facility freeze-ups, trucking curtailments and limited access to production and drilling facilities. In addition, the forecasted production for the quarter reflects reduced NGL production volumes of approximately 4,000 BOEPD due to not recovering ethane since it has a higher value if left in the gas stream.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $13.25 to $15.25 per BOE, based on current NYMEX strip prices for oil and gas. DD&A expense is expected to average $16.00 to $18.00 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $25 million to $35 million. General and administrative expense is expected to be $78 million to $83 million. Interest expense is expected to be $45 million to $50 million, and other expense is expected to be $30 million to $40 million. Accretion of discount on asset retirement obligations is expected to be $3 million to $5 million.

The Company's first quarter effective income tax rate is expected to range from 35 percent to 40 percent, assuming current capital spending plans and no significant derivative MTM changes in the Company's derivative position. Cash income taxes are expected to be $1 million to $5 million and are primarily attributable to state taxes.

2015 Capital Budget

Pioneer's capital program for 2015 totals $1.85 billion, consisting of $1.6 billion for drilling operations, including budgeted land capital for existing assets, and $250 million for other property and equipment. The 2015 budget excludes acquisitions, asset retirement obligations, capitalized interest, and geological and geophysical general and administrative expense.

The 2015 drilling capital of $1.6 billion continues to be focused on oil- and liquids-rich drilling, with substantially all of the capital allocated to the Spraberry field and the Eagle Ford Shale play. The following is the forecasted spending by asset area:

- Spraberry field - $1.17 billion, including (i) $1.05 billion of capital in the northern Spraberry/Wolfcamp acreage, which includes $735 million of horizontal drilling capital, $20 million of vertical drilling capital and $295 million for infrastructure, gas processing facilities and land and (ii) $120 million for drilling and facilities capital in the southern Wolfcamp joint interest area;
- Eagle Ford Shale - $390 million, including $335 million of horizontal drilling capital and $55 million for facilities and land; and
- Other spending - $40 million for other existing assets.

Pioneer's budgeted expenditures for other property and equipment in 2015 include:

- Vertical integration capital - $185 million;
- Buildings and other facilities - $50 million; and
- Vehicles and other equipment - $15 million.

The 2015 capital budget is expected to be funded from a combination of operating cash flow, cash and cash equivalents on hand, and, if necessary, borrowings under the Company's credit facility or proceeds from planned divestitures.

Acquisitions

During 2014, 2013 and 2012, the Company spent $104 million, $76 million and $158 million, respectively, to acquire primarily undeveloped acreage for future exploitation and exploration activities. The 2014, 2013 and 2012 acquisitions primarily increased the Company's acreage positions in the West Texas Spraberry field. During 2013, the Company completed the acquisition of all of the outstanding common units of Pioneer Southwest not already owned by the Company in exchange for 0.2325 of a share of common stock of the Company per Pioneer Southwest common unit. Additionally, in 2012, the Company acquired Premier Silica for $297 million. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's acquisitions.

Divestitures and Discontinued Operations

Hugoton. In September 2014, the Company completed the sale of its net assets in the Hugoton field in southwest Kansas for cash proceeds of $328 million, including normal closing adjustments.

Table of Contents

Barnett Shale. During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. In September 2014, the Company completed the sale of its Barnett Shale net assets for cash proceeds of $150 million, including normal closing adjustments.

Pioneer Alaska. During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer Alaska. In April 2014, the Company completed the sale of Pioneer Alaska for cash proceeds of $267 million, including normal closing and other adjustments.

Pioneer South Africa. During the first quarter of 2012, the Company agreed to sell its net assets in Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for cash proceeds of $16 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale.

The Company has reflected its Hugoton, Barnett Shale, Pioneer Alaska and Pioneer South Africa results of operations as discontinued operations in the accompanying consolidated statements of operations.

Sendero. During December 2013, the Company committed to a plan to sell the Company's majority interest in Sendero to Sendero's minority interest owner. At December 31, 2013, the assets and liabilities of Sendero were classified as held for sale at their estimated fair value. In March 2014, the Company completed the sale of Sendero for cash proceeds of $31 million. As part of the sales agreement, the Company committed to lease from Sendero 12 vertical rigs through December 31, 2015 and eight vertical rigs in 2016.

Southern Wolfcamp. In January 2013, the Company signed an agreement with Sinochem to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for total consideration of $1.8 billion. In May 2013, the Company completed the sale for net cash proceeds of $624 million, resulting in a gain of $181 million. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play. At December 31, 2014, the unused carry balance totaled $575 million.

See Notes C and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's divestitures, impairments and discontinued operations.

Results of Operations

Oil and gas revenues. Oil and gas revenues from continuing operations totaled $3.6 billion, $3.1 billion and $2.5 billion during 2014, 2013 and 2012, respectively.

The increase in 2014 oil and gas revenues relative to 2013 is reflective of 25 percent, 29 percent and three percent increases in oil, NGL and gas sales volumes, respectively, and a 21 percent increase in average reported gas prices. Partially offsetting the effects of these increases were declines of eight percent and 10 percent in average reported oil and NGL prices, respectively.

The increase in 2013 oil and gas revenues relative to 2012 is reflective of 22 percent, 22 percent and one percent increases in oil, NGL, and gas sales volumes, respectively, and two percent and 32 percent increases in average reported oil and gas prices, respectively. Partially offsetting the effects of these increases was a decline of 12 percent in average reported NGL prices.

The following table provides average daily sales volumes from continuing operations for 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Oil (Bbls)	87,034	69,527	57,165
NGLs (Bbls)	38,646	29,910	24,557
Gas (Mcf)	339,341	331,003	329,228

Total (BOE)	182,237	154,604	136,593

Average daily BOE sales volumes from continuing operations in 2014 and 2013 increased by 18 percent and 13 percent, respectively, as compared to the daily sales volumes in the respective prior years, principally due to the Company's successful drilling programs.

Production for the year ended December 31, 2013 was negatively impacted by approximately 600 BOEPD related to gas processing capacity limitations that were resolved in mid-April and by approximately 1,500 BOEPD related to severe winter weather during the fourth quarter.

The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Oil (Bbls):			
United States	2,605	5,693	5,480
South Africa	—	—	428
Worldwide	2,605	5,693	5,908
NGL (Bbls):			
United States	4,535	5,705	5,259
Gas (Mcf):			
United States	37,881	49,484	49,141
South Africa	—	—	10,340
Worldwide	37,881	49,484	59,481
Total (BOE):			
United States	13,453	19,645	18,929
South Africa	—	—	2,151
Worldwide	13,453	19,645	21,080

The oil, NGL and gas prices that the Company reports are based on the market prices received for the commodities. The following table provides the Company's average prices from continuing operations for 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012 (a)
Oil (per Bbl)	$85.29	$92.62	$90.67
NGL (per Bbl)	$27.06	$29.99	$34.08
Gas (per Mcf)	$4.10	$3.39	$2.56
Total (per BOE)	$54.11	$54.71	$50.24

(a) For the year ended December 31, 2012, the Company's average realized oil price per Bbl was $88.81 and the average realized total price per BOE was $49.46. The average realized price does not include the impact of transfers of the Company's deferred hedge gains and losses from Accumulated Other Comprehensive Income ("AOCI-Hedging") and the amortization of deferred VPP revenue. During the year ended December 31, 2012, the Company transferred $3 million of deferred oil hedge losses from AOCI-Hedging to oil revenue. The transfer represented all of the remaining AOCI-Hedging transfers to earnings. Amortization of deferred VPP revenue increased oil revenues by $42 million during the year ended December 31, 2012. As of December 31, 2012, all VPP production volumes had been delivered and there are no further obligations under VPP contracts.

Sales of purchased oil and gas. The Company periodically enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to satisfy unused pipeline capacity commitments and to diversify a portion of the Company's WTI oil sales to a Gulf Coast market price. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming the risk and rewards of ownership, including credit risk, of the commodities purchased and assuming responsibility to deliver the commodities sold. Deficiency payments on excess pipeline capacity are included in other expense in the accompanying consolidated statements of operations. See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for further information on transportation commitment charges.

Interest and other income. The Company's interest and other income from continuing operations was $9 million and $17 million during 2014 and 2013, respectively, and a loss of $1 million in 2012. The $8 million decrease during 2014, as compared to 2013, is primarily attributable to an $11 million increase between periods in the loss attributable to vertical integration services provided to third-party working interest owners in wells owned and operated by the Company and a $3 million decrease in deferred compensation plan income, partially offset by a $6 million increase in equity in earnings of EFS Midstream. The $18 million increase during 2013, as compared to 2012, was primarily attributable to a $7 million reduction in losses from vertical integration services, a $5 million increase in equity in earnings of EFS Midstream and a $4 million increase in deferred compensation plan income. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's interest and other income.

Derivative gains, net. The Company utilizes commodity swap contracts, collar contracts and collar contracts with short puts in order to (i) reduce the effect of price volatility on the commodities the Company produces, sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. In 2009, the Company discontinued hedge accounting on all of its then-existing derivative contracts. Changes in the fair value of effective cash flow hedges prior to the Company's discontinuance of hedge accounting were recorded as a component of AOCI-Hedging in the equity section of the Company's consolidated balance sheets, and were transferred to earnings during the same periods in which the hedged transactions were recognized in the Company's earnings. Since 2009, the Company has recognized all changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur. All deferred oil hedge losses were transferred from AOCI-Hedging to earnings during the year ended December 31, 2012. Transfers of deferred hedge gains and losses associated with oil cash flow hedges from AOCI-Hedging to oil revenues for the year ended December 31, 2012 resulted in a decrease of $3 million to oil revenue.

The following table summarizes the Company's net derivative gains or losses for the years ending December 31, 2014, 2013 and 2012 (in millions):

	Year Ended December 31,		
	2014	2013	2012
Noncash changes in fair value:			
Oil derivative gains (losses)	$514	$(19)	$218
NGL derivative gains (losses)	4	(1)	1
Gas derivative gains (losses)	91	(154)	(290)
Marketing derivative gains	3	—	—
Interest rate derivative gains (losses)	(3)	10	6
Total noncash derivative gains (losses), net	609	(164)	(65)
Net cash receipts (payments) on settled derivative instruments:			
Oil derivative receipts	104	12	4
NGL derivative receipts	8	1	13
Gas derivative receipts (payments)	(27)	155	403
Diesel derivative receipts	—	—	3
Interest rate derivative receipts (payments)	18	—	(28)
Total cash receipts on settled derivative instruments, net	103	168	395
Total derivative gains, net	$712	$4	$330

The Company's open derivative contracts are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's derivative contracts.

Gain on disposition of assets, net. The Company recorded net gains on the disposition of assets of $9 million, $209 million and $46 million during 2014, 2013 and 2012, respectively.

During 2013, the Company's gains on disposition of assets included a $181 million gain on the sale of a 40 percent interest in the Company's horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas to Sinochem and a gain of $22 million on the sale of the Company's interest in unproved oil and gas properties adjacent to the Company's West Panhandle field operations. During 2012, the Company recorded a $43 million gain on the sale of a portion of its interest in an unproved oil and gas property in the Eagle Ford Shale field.

Oil and gas production costs. The Company's oil and gas production costs from continuing operations totaled $693 million, $588 million and $532 million during 2014, 2013 and 2012, respectively. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while third-party transportation charges represent the cost to transport volumes produced to a sales point. Net natural gas plant/gathering charges represent the net costs to gather and process the Company's gas, reduced by net revenues earned from gathering and processing of third party gas in Company-owned facilities.

Total oil and gas production costs per BOE for the year ended December 31, 2014 did not substantially change as compared to 2013. During 2013, total production costs per BOE decreased by two percent as compared to 2012. The decrease in production costs per BOE during 2013 was primarily reflective of a $0.43 per BOE decrease in net natural gas plant charges as a result of higher gas prices being realized on third-party volumes that are retained as processing fees in Company-owned facilities. Partially offsetting the decrease in per BOE net natural gas plant charges was a $0.26 per BOE increase in third-party transportation charges, primarily associated with increasing Eagle Ford Shale sales volumes.

The following table provides the components of the Company's total production costs per BOE for 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Lease operating expenses	$8.27	$8.19	$8.15
Third-party transportation charges	1.68	1.59	1.33
Net natural gas plant/gathering charges	(0.20)	(0.16)	0.27
Workover costs	0.65		