PIONEER NATURAL RESOURCES CO
Form 10-K
February 13, 2013

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, 2012
or

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

For the transition period from to
Commission File Number: 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 is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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	$10,710,105,448
Number of shares of Common Stock outstanding as of February 8, 2013	123,360,341

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's 2013 Annual Meeting of Shareholders to be held during May 2013 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 6.0 MCF of gas to 1.0 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-posted price" means the daily average natural gas liquids components as priced in Oil Price Information Services 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-posted price" means the daily average natural gas liquids components as priced in Oil Price Information Service 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 reserves" mean the 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 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 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. (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,

Table of Contents

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.

- "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 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

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.

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 Anchorage, Alaska; Denver, Colorado and Midland, Texas. At December 31, 2012, the Company had 3,667 employees, 2,484 of whom were employed in field and plant operations.

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.

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 oil field; the liquid-rich Eagle Ford Shale, Barnett Shale Combo, Hugoton and West Panhandle fields; and the Raton gas field; which together have an estimated remaining productive life in excess of 40 years. Underlying these fields are 94 percent of the Company's proved oil and gas reserves as of December 31, 2012.

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. While oil and NGL prices generally improved from 2009 through 2011, during 2012, oil and NGL production growth in the United States outpaced demand growth causing prices to become more volatile and decline during the year. North American gas prices have remained volatile and have generally trended lower since 2009. The decline in North American gas prices is primarily a result of growing gas supplies associated with discoveries of significant gas reserves in United States shale plays, combined with the warmer than normal recent winters, which has resulted in gas storage levels being at historically high levels, and minimal economic demand growth in the United States. Oil prices continue to be primarily driven by world supply and demand fundamentals; however, recent increases in United States oil, NGL and gas production volumes from the Permian Basin, Eagle Ford, Bakken and Marcellus areas have been met with lower demand, higher storage levels and pipeline, gas plant and NGL fractionation infrastructure capacity limitations, which has led to a reduction in United States NYMEX oil, NGL and gas prices compared to international prices for similar commodities, including Brent oil prices.

During 2010, 2011 and 2012, the economies in the United States and certain other countries stabilized 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, it is still uncertain; therefore, the sustainability of the 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 2013.

Significant factors that will affect 2013 commodity prices include: 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 the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations are able to manage oil supply through export quotas; and overall North American NGL and gas supply and demand fundamentals.

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 2014, 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, 2012.

The Company. The Company's growth plan is anchored primarily by drilling in the Spraberry oil field located in West Texas, the liquid-rich Eagle Ford Shale field located in South Texas, the liquid-rich Barnett Shale Combo field in North Texas and, to a lesser extent, Alaska. 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 Hugoton gas and liquid field located in southwest Kansas, the West Panhandle gas and liquid 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 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.

The Company provides administrative, financial, legal and management support to subsidiaries that explore for, develop and produce proved reserves. The Company's continuing operations are located in the United States, principally in the states of Texas, Kansas, Colorado and Alaska.

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, 2012, the Company's production from continuing operations of 56.9 MMBOE, excluding field fuel usage, represented a 29 percent increase over production from continuing operations during 2011. Production, price and cost information with respect to the Company's properties for 2012, 2011 and 2010 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 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, 2012, the Company drilled 1,844 gross (1,655 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 $4.0 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, 2012 include proved undeveloped reserves and proved developed reserves that are behind pipe of 271.4 MMBBLs of oil, 103.0 MMBBLs of NGLs and 714.6 Bcf of gas. The Company believes that its current portfolio of proved reserves provides attractive development opportunities for at least the next five years. 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 expand its integrated services to control drilling and operating costs and support the execution of its drilling program and operating activities. The Company has 15 owned vertical drilling rigs operating in the Spraberry field, and at the end of 2012, had Company-owned fracture stimulation fleets totaling 300,000 horsepower supporting drilling operations in the Spraberry, Eagle Ford Shale and Barnett Shale Combo areas. During April 2012, the Company acquired 100 percent of the share capital of Industrial Sands Holding Company and its wholly-owned subsidiary, Oglebay Norton Industry Sands, LLC, for an aggregate purchase price of $297.1 million. The Company changed the name of the Oglebay Norton Industrial Sands LLC to Premier Silica LLC ("Premier Silica") in April 2012. 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. 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.

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 2012, 2011 and 2010, the Company spent $157.5 million, $131.9 million and $181.6 million, respectively, to purchase primarily undeveloped acreage for future exploitation and exploration activities.

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.

In January 2013, the Company signed an agreement with Sinochem Petroleum USA LLC ("Sinochem"), a U.S. subsidiary of the Sinochem Group, 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 $1.7 billion. At closing, Sinochem will pay $522.0 million in cash to Pioneer, before normal closing adjustments, and will pay the remaining $1.2 billion by carrying 75 percent of Pioneer's portion of future drilling and facilities costs attributable to the horizontal Wolfcamp Shale play. This transaction is expected to close during the second quarter of 2013, subject to governmental and third party approvals.

During December 2011, the Company committed to a plan to exit South Africa and initiated a process to divest its net assets in South Africa ("Pioneer South Africa"). During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60.0 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 net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a pretax gain of $28.6 million. The Company classified (i) Pioneer South

Africa's assets and liabilities as discontinued operations held for sale in the accompanying consolidated balance sheet as of December 31, 2011 and (ii) Pioneer South Africa's results of operations as income from discontinued operations, net of tax, in the accompanying consolidated statements of operations.

In February 2011, the Company sold 100 percent of the Company's share holdings in Pioneer Natural Resources Tunisia Ltd. and Pioneer Natural Resources Anaguid Ltd. (referred to in the aggregate as "Pioneer Tunisia") to an unaffiliated third party for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a pretax gain of $645.2 million. Accordingly, the Company has classified the results of operations of Pioneer Tunisia, prior to its sale, as discontinued operations, net of tax, in the accompanying consolidated statements of operations.

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 Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures and discontinued operations, including the 2011 sale of Pioneer Tunisia and 2012 sale of Pioneer South Africa.

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 2012, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (26 percent), Enterprise Products Partners L.P. (15 percent) and Occidental Energy Marketing Inc. (14 percent). The Company believes that 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 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 utilizes commodity swap contracts to reduce price volatility on the fuel that the Company's drilling rigs and fracture stimulation fleets consume. 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 2012, 2011 and 2010, as well as the Company's open commodity derivative positions at December 31, 2012.

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. Many 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 environmental protection, worker health and safety, and the discharge of materials into the environment. 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 can 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; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules 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 affect the environment. Any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant effect on the Company's operating costs.

The Company believes it is in substantial compliance with all existing environmental laws and regulations applicable to the Company's current operations and that its continued compliance with existing requirements will not have a material adverse effect on the Company's financial condition and results of operations. For example, the Company did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2012. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2013. Nevertheless, accidental spills or releases may occur in the course of the Company's operations, and the Company cannot give any assurance that it will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, the Company cannot give any assurance that the passage of more stringent laws or regulations in the future will not have a negative effect on the Company's business, financial condition and results of operations.

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.

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 federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. 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 certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. 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. Also, in the course of the Company's operations, it 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 Occupational Safety and Health Administration ("OSHA"). These state and OSHA regulations impose certain requirements concerning worker protection; the treatment, storage and disposal of NORM waste; the management of waste piles, containers and tanks containing NORM; as well as 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. 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 recycling 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 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 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 been required to engage pursuant to OPA to address such oil spills.

Operations associated with the Company's properties also produce wastewaters that are disposed via injection in underground wells. These injection wells are regulated by the Safe Drinking Water Act (the "SDWA") and analogous state and local laws. The underground injection well program under the SDWA requires permits from the EPA or 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. Currently, the Company believes that disposal well operations on the Company's properties comply with all applicable requirements under the SDWA. However, a change in the regulations or the inability to obtain permits for new injection 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. In addition, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. The U.S. Geological Survey is advising the EPA regarding potential seismic hazards associated with these types of underground injection wells. It is possible that federal or state agencies will seek to regulate more stringently the underground injection of oil and gas wastewaters as a result of these events. Nevertheless, the Company is not aware of any imminent actions by federal or state agencies that would affect its use or operation of underground injection wells.

The Company also routinely uses hydraulic fracturing techniques in the majority of its drilling and completion programs in Texas, Colorado and elsewhere, where development of most of the Company's properties are 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; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the SDWA Underground Injection Control Program and has published draft permitting guidance in May 2012 addressing the performance of such activities. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and the agency currently projects to issue an Advance Notice of Proposed Rulemaking in May 2013 that would seek public input on the design and scope of such disclosure regulations. In August 2012, the EPA published final rules under the federal Clean Air Act ("CAA"), which became effective October 15, 2012, that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 or performing reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. In addition, the U.S. Congress, from time to time, 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 the event that new federal restrictions relating to the hydraulic-fracturing process are adopted in areas where the Company currently operates or in the future plans to operate, the Company may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

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. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (the "TRRC") and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. 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 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 were recently conducted or 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, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report released by the agency on December 21, 2012 and a final report expected to be available for public comments and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

The water produced by the Company's CBM operations also may be subject to the laws of various states and 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. In a 2008 case brought by the owners of ranch land involving a CBM competitor in a different CBM basin in Colorado, the Colorado Supreme Court held 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, but there continue to be litigation and uncertainty regarding permitting of produced water withdrawn in connection with CBM activities. The Company's CBM or other oil and gas operations and the Company's ability to expand its operations could be adversely affected, and these changes in regulation could ultimately increase the Company's cost of doing business.

Air emissions. 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. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Moreover, states can impose air emissions limitations that are 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.

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 gas and oil exploration and production operations. On August 16, 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 regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flowback emissions to a gathering line or capture and combust flowback emissions using a combustion device, such as a flare, after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions, " with or without combustion devices, on or after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. The Company is currently reviewing this new rule and assessing its potential effects on its operations. Compliance with these requirements could increase the Company's costs of development and production, which costs could be significant.

In addition, in response to reported concerns about high concentrations of benzene in the air near certain drilling sites and gas processing facilities in the Barnett Shale area, the Texas Commission on Environmental Quality (the "TCEQ") adopted new air emissions limitations and permitting requirements for oil and gas facilities in the state, which are applicable to facilities located in the Barnett Shale area. These new requirements could increase the cost and time associated with drilling wells in the Barnett Shale. The agency's investigations could lead to additional, more stringent air permitting requirements, increased regulation, and possible enforcement actions against producers, including Pioneer, in the Barnett Shale area. Any adoption of laws, regulations, orders or other legally enforceable mandates governing gas drilling and operating activities in the Barnett Shale or other areas of Texas that result in more stringent drilling or operating conditions or limit or prohibit the drilling of new wells for any extended period of time could increase the Company's costs or reduce its production, which could have a material adverse effect on the Company's results of operations and cash flows.

Some gas and oil production facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. 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.

As a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the ESA and issue decisions with respect to the 250 candidate species 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 exploration and production activities that could have an adverse effect on the Company's ability to develop and produce its proved reserves.

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.

Global warming and climate change. In December 2009, the EPA officially 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 adopted regulations under the CAA in 2010 establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHGs. 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. 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, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on the Company's operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would affect the Company's business, any such future laws and regulations 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. Any such legislation or regulatory programs could also increase the cost of consuming, 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.

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, 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 exploration 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 up to $1.0 million per day per violation of the NGA and 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.

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. 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 ("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 ("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 and the FTC 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 gas, oil, condensate and NGLs 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, or the prices charged for these commodities might be proposed, what proposals, if any, 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" 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, NGL and gas are highly volatile. A sustained decline in these commodity prices could adversely affect the Company's 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, NGL 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, NGL and gas;
- inventory levels at Cushing, Oklahoma, the benchmark for WTI oil prices;

- gas inventory levels in the United States;
- weather conditions;
- overall domestic and global political and economic conditions;
- 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 example, during 2012, oil prices fluctuated from a high of $109.77 per BBL in February to a low of $77.69 per BBL in June, while gas prices fluctuated from a low of $1.91 per MCF in April to a high of $3.90 per MCF in November. During 2011, oil prices fluctuated from a high $113.93 per BBL in April to a low of $75.67 per BBL in October, while gas prices fluctuated from a high of $4.85 per MCF in June to a low of $2.99 per MCF in December. 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 noncancellable 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, NGL and gas that the Company can produce economically. A reduction in production could 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 achieve more predictable cash flow and to manage the Company's exposure to fluctuations in the prices of oil, NGL and gas, 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 unrealized net 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.

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 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 2013.

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.

Declines in commodity prices may result in the Company having to make substantial downward adjustments to its estimated proved reserves. If this occurs, or if the Company's estimates of production or economic factors change, accounting rules may require the Company 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. For example, during 2012 and 2011, the Company recognized impairment charges of $532.6 million and $354.4 million, respectively, due to the impairment of the Company's Barnett Shale field and Edwards and Austin Chalk gas fields in South Texas, primarily due to declines in gas prices and downward adjustments to the economically recoverable resource potential. 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, 2012, the Company carried unproved property costs of $231.6 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, 2012, the Company carried goodwill of $298.1 million. Goodwill is tested for impairment annually during the third quarter using a July 1 assessment date, and also whenever facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, requiring 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, 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 (as is the case with respect to the Company's southern Wolfcamp joint interest transaction) and the availability of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and at prices acceptable to the Company. For example, during the fourth quarter of 2012, the Company was unable to dispose of its Barnett Shale assets under acceptable terms. Consequently, the Company no longer expects to dispose of the Barnett Shale assets during 2013 and has reclassified the Barnett Shale assets to held for use and their historical results of operations to continuing operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information about the Barnett Shale disposition plans.

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, 2012, the Company owned interests in four gas processing plants and ten treating facilities. The Company is the operator of two of the gas processing plants and all ten 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 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 drilling, fracture stimulation 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.

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 and enhanced recovery 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, 2012 include proved undeveloped reserves and proved developed reserves that are behind pipe of 271.4 MMBBLs of oil, 103.0 MMBBLs of NGLs and 714.6 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 and personnel and drilling results. 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 and enhanced recovery 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.

The Company may not be able to obtain access 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, NGL 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. 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.

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 nature of the Company's assets and production operations exposes it to significant costs and liabilities with respect to environmental and occupational 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 operations upon the Company's properties due to its handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and as a result of historical 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 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 indemnity.

The Company's credit facilities 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, convertible senior notes and credit facilities. The terms of the Company's borrowings under the senior notes, convertible senior notes and the credit facilities 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, 2012 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.

Table of Contents

The Company faces significant competition, and many 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 properties.

Many 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 business is regulated by a variety of federal, state and local laws and regulations. For instance, 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. 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, gas, NGLs 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, gas, NGLs 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 business 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 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.

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.

A subsidiary of the Company acts as the general partner of a publicly-traded limited partnership. As such, the subsidiary's operations may involve a greater risk of liability than ordinary business operations.

A subsidiary of the Company acts as the general partner of Pioneer Southwest, a publicly-traded limited partnership formed by the Company to own, develop and acquire oil and gas assets in its area of operations. As general partner, the subsidiary may be deemed to have undertaken fiduciary obligations to Pioneer Southwest.

Activities determined to involve fiduciary obligations to others typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interest is found to exist. Any such liability may be material.

The tax treatment of Pioneer Southwest depends on its status as a partnership for federal income tax purposes as well as its not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (the "IRS") were to treat Pioneer Southwest as a corporation for federal income tax purposes or Pioneer Southwest becomes subject to a material amount of entity-level taxation for state tax purposes, then the value of the Company's investment in Pioneer Southwest would be substantially reduced.

The Company currently owns a 52.4 percent limited partner interest and a 0.1 percent general partner interest in Pioneer Southwest. The value of the Company's investment in Pioneer Southwest depends largely on its being treated as a partnership for federal income tax purposes. A publicly traded partnership may be treated as a corporation for United States federal income tax purposes unless 90 percent or more of its gross income for every year is "qualifying income" under section 7704 of the Internal Revenue Code of 1986, as amended. Pioneer Southwest has not requested and does not plan to request a ruling from the IRS with respect to its treatment as a partnership for federal income tax purposes.

A change in Pioneer Southwest's business could cause it to be treated as a corporation for federal income tax purposes. In addition, a change in current law may cause Pioneer Southwest to be treated as a corporation for such purposes. For example, members of U.S. Congress have from time to time considered substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Moreover, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If Pioneer Southwest were subject to federal income tax as a corporation or any state were to impose a tax upon Pioneer Southwest, its cash available to pay distributions would be reduced. Therefore, treatment of Pioneer Southwest as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to Pioneer Southwest's unitholders, including the Company, and would likely cause a substantial reduction in the value of the Company's investment in Pioneer Southwest.

Pioneer Southwest's partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects it to taxation as a corporation or otherwise subjects it to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution and the target distribution amounts may be adjusted to reflect the effect of that law on Pioneer Southwest.

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 perform 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.

While the credit and equity markets have improved during 2010, 2011 and 2012, the economic outlook for 2013 remains uncertain. 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.

Concerns over the worldwide economic outlook, geopolitical issues, the availability and cost of credit and the U.S. mortgage and real estate markets have contributed to increased volatility and diminished expectations for the global economy. These factors, combined with volatile commodity prices, declining business and consumer confidence and increased unemployment resulted in a worldwide recession. While the worldwide economic outlook seems to be improving, concerns about global economic growth or government debt in Europe or the United States could have 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 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 this legislation 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 negatively affect the value of an investment in the Company's common stock and defer planned capital expenditures if such changes accelerated the payment of taxes.

The adoption of climate change legislation by the U.S. Congress or regulation by the EPA could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces.

In December 2009, the EPA officially 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 adopted regulations under the CAA in 2010 establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHGs. 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. 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. The Company is monitoring GHG emissions from its operations in accordance with these GHG emissions reporting rules and believes that 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, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on the Company's operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would affect the Company's business, any such future laws and regulations 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. Any such legislation or regulatory programs could also increase the cost of consuming, 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. Also, 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, and 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. See "Item 1. Business – Competition, Markets and Regulations - Environmental and occupational health and safety matters - Global warming and climate change" for additional discussion relating to global warming and 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 "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 Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Act. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide derivative transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant." The Act and the CFTC rules also will require the Company, in connection with certain derivative activities, to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require the Company to comply with margin requirements although these regulations are not finalized and their application to the Company is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Act and the CFTC rules on the Company and the timing of such effects. The Act also may require the counterparties to the Company's derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect the Company's available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less creditworthy counterparties. If the Company reduces its use of derivatives as a result of the Act and regulations implementing the Act, 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 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 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.

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 an important and 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; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the SDWA's Underground Injection Control Program and published draft permitting guidance in May 2012 addressing the performance of such activities. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and the agency currently projects to issue an Advance Notice of Proposed Rulemaking in May 2013 that would seek public input on the design and scope of such disclosure regulations. In August 2012, the EPA published final rules under the CAA, which became effective October 15, 2012, that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 or performing reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. In addition, the U.S. Congress, from time to time, 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 the event that a new federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where the Company currently or in the future plans to operate, the Company may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

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. For example, Texas adopted a law in June 2011 requiring disclosure to the TRRC and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. 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 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 were recently conducted or 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, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress released by the agency on December 21, 2012 and a final report expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. See "Item 1. Business - Competition, Markets and Regulations - Environmental and occupational health and safety matters" above for additional discussion related to environmental risks associated with the Company's hydraulic fracturing activities.

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 transaction and thereby negatively affect the price that investors might be willing to pay in the future for the Company's common stock.

The Company is growing production 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 has 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, has increased, as have 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. Any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for the Company to complete its planned 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 profitability.

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 and CERCLA. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. 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 U.S. Fish and Wildlife Service is required to consider listing more than 250 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 limitations on its exploration and production activities that could have an adverse effect on the Company's ability to develop and produce reserves.

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 are 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;
- 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 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 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 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 entail 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, and may continue to be, 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 employee 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 customers alleging damages caused by silica exposure. As of December 31, 2012, Premier Silica was the subject of approximately 2,500 silica exposure claims, the great majority of which 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, Louisiana, Florida and West Virginia, although some cases have been brought in many other jurisdictions over the years.

It is possible that Premier Silica will continue to have silica-related products liability claims filed against it, including claims that allege silica exposure for periods for which there is not insurance coverage. Any pending or future claims or inadequacies of insurance coverage or indemnification from the seller could have a material adverse effect on the Company's results of operations.

The Company's pending sale of 40 percent of its acreage in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field is contingent upon the satisfaction of certain conditions and may not be consummated on the terms or timeline contemplated and may not achieve the intended results.

In January 2013, the Company agreed to sell 40 percent of its interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field to Sinochem, an unaffiliated third party, for consideration of $1.7 billion. At closing, Sinochem will pay $522.0 million in cash to Pioneer, before normal closing adjustments, and will pay the remaining $1.2 billion by carrying 75 percent of the Company's portion of future drilling and facilities costs attributable to the horizontal Wolfcamp Shale play. The Company expects this transaction to close during the second quarter of 2013. However, the parties' obligations to consummate this transaction are conditioned upon the satisfaction or waiver of certain closing conditions, including governmental and third party approvals. If these conditions are not satisfied or waived, the acquisition will not be consummated. If the closing of the transaction is substantially delayed or does not occur at all, the Company may not realize the anticipated benefits of the transaction fully or at all. Further, if the transaction is not completed, the Company would need to reevaluate its capital expenditure budget and reduce its activities or obtain funding from other sources.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Reserve Estimation Procedures and Audits

The information included in this Report about the Company's proved reserves as of December 31, 2012, 2011 and 2010 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) with respect to the Company's Oooguruk field properties in Alaska, audited by Ryder Scott Company, L.P. ("RSC"), 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. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the sale of the Company's share holdings in Pioneer Tunisia during February 2011 and the Company's sale of Pioneer South Africa in August 2012.

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 Worldwide Reserves Group (the "WWR"), and annual external audits of substantial portions of the Company's proved reserves by NSAI and RSC.

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, South Texas, Barnett Shale and Alaska 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 Director of the WWR, 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 the WWR 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 the WWR, 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 and 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, the WWR 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 2012, 2011 and 2010, and by RSC for 2012, in the aggregate represented 95 percent, 90 percent and 90 percent of the Company's 2012, 2011 and 2010 proved reserves, respectively; and, 99 percent, 91 percent and 79 percent of the Company's 2012, 2011 and 2010 associated pre-tax present value of proved reserves discounted at ten percent, respectively.

Table of Contents

NSAI and RSC follow 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."
- 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 its 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 and RSC its external and internal engineering and geoscience technical data and analyses. Following the reserve auditors' review of that data, they had the option of honoring Pioneer's interpretations, or making their own interpretations. No data was withheld from NSAI or RSC. The reserve auditors 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 their evaluations something came to their attention that brought into question the validity or sufficiency of any such information or data, the reserve auditors did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data.

In the course of their evaluations, NSAI and RSC prepared, for all of the audited properties, their own estimates of the Company's proved reserves and the pre-tax present values of such reserves discounted at ten percent. The reserve auditors reviewed their 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. The reserve auditors' 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 and RSC are satisfied that the proved reserves and pre-tax present values of such reserves discounted at ten percent are reasonable and that their audit objectives have been met, NSAI and RSC 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 the opinions of NSAI and RSC, as set forth in their audit letters, which are included as exhibits 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 reserves preparers and auditors. The WWR is staffed by petroleum engineers with extensive industry experience and is managed by the Director of the WWR, 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 WWR Director's qualifications include 35 years of experience as a petroleum engineer, with 28 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 34 years of practical experience in petroleum engineering, including over 32 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 reserves estimates has been a practicing consulting petroleum engineer at RSC since 2000 and has 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 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.

Technologies used in 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 reserve estimates.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

Proved Reserves

As of December 31, 2012, the Company's oil and gas proved reserves are located entirely in the United States. Less than one percent of proved reserves as of December 31, 2011 were associated with discontinued operations in South Africa and three percent of proved reserves as of December 31, 2010 were associated with discontinued operations in South Africa and Tunisia. 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 and Standardized Measure as of December 31, 2012, 2011 and 2010:

	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)	%	Standardized Measure (in thousands)
December 31, 2012:						
Developed	230,700	134,637	1,605,209	632,872	58 %	$5,010,779
Undeveloped	256,138	97,939	592,271	452,789	42 %	1,342,619
Total Proved	486,838	232,576	2,197,480	1,085,661	100 %	$6,353,398
December 31, 2011:						
Developed	190,206	120,405	1,853,363	619,506	58 %	$5,494,007
Undeveloped	239,799	90,630	677,675	443,375	42 %	$2,319,016
Total Proved	430,005	211,035	2,531,038	1,062,881	100 %	$7,813,023
December 31, 2010:						
Developed	172,816	108,785	1,775,611	577,537	57 %	$4,065,879
Undeveloped	207,993	75,433	898,911	433,244	43 %	$1,346,130
Total Proved	380,809	184,218	2,674,522	1,010,781	100 %	$5,412,009

(a) The gas reserves contain 280,344 MMCF, 301,123 MMCF and 303,748 MMCF of gas that will be produced and used as field fuel (primarily for compressors) before the gas is delivered to a sales point, for December 31, 2012, 2011 and 2010, respectively.

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.

Description of Properties

Approximately 78 percent of the Company's proved reserves at December 31, 2012 are located in the Spraberry field in the Permian Basin area, the Hugoton and West Panhandle fields in the Mid-Continent area and the Raton field in the Rocky Mountains area. These fields generate substantial operating cash flow, which provides funding for the Company's development and exploration activities in the Spraberry field, Eagle Ford Shale play, Barnett Shale Combo play and Alaska.

The following tables summarize the Company's development and exploration/extension drilling activities during 2012:

	Development Drilling				
	Beginning Wells	Wells	Successful	Unsuccessful	Ending Wells

	In Progress	Spud	Wells	Wells	In Progress
Permian Basin	161	633	649	9	136
Raton Basin	5	—	4	1	—
Barnett Shale	—	4	4	—	—
Alaska	1	5	2	—	4
Total	167	642	659	10	140

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

	Exploration/Extension Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	—	50	33	—	17
Mid-Continent	5	—	—	5	—
South Texas—Eagle Ford Shale	39	130	137	—	32
Barnett Shale	26	36	53	—	9
Alaska	1	2	—	1	2
Total	71	218	223	6	60

The following table summarizes the Company's average daily oil, NGL, gas and total production by asset area during 2012:

	Oil (BBLs)	NGLs (BBLs)	Gas (MCF) (a)	Total (BOE)
Permian Basin	44,042	12,623	61,922	66,985
Mid-Continent	3,175	7,102	46,192	17,976
Raton Basin	—	—	149,787	24,965
Barnett Shale	1,210	2,756	20,085	7,314
South Texas—Eagle Ford Shale	9,871	7,332	63,338	27,759
South Texas—Edwards and Austin Chalk	75	1	36,945	6,233
Alaska	4,269	—	—	4,269
Other	3	2	100	21
Total	62,645	29,816	378,369	155,522

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

The following table summarizes the Company's costs incurred by asset area during 2012:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in thousands)					
Permian Basin	$4,755	$70,558	$441,127	$1,603,688	$36,221	$2,156,349
Mid-Continent	—	4,211	4,136	17,884	529	26,760
Raton Basin	—	—	8,111	7,467	16,254	31,832
South Texas—Eagle Ford Shale	—	12,194	229,364	9,476	1,461	252,495
South Texas—Edwards and Austin Chalk	—	130	4,534	5,434	1,502	11,600
Barnett Shale	12,114	12,288	200,376	60,606	(317)	285,067
Alaska	—	106	73,475	120,246 (a)	3,241	197,068
Other	69	41,028	3,505	10	(19)	44,593
Total	$16,938	$140,515	$964,628	$1,824,811	$58,872	$3,005,764

(a) Includes $8.5 million of capitalized interest associated with the Oooguruk development project.

Permian Basin

Spraberry field. The Spraberry field was discovered in 1949 and encompasses eight counties in West Texas. According to the Energy Information Administration, the Spraberry field is the second 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 four formations, the upper and lower Spraberry, the Dean and the Wolfcamp, at depths ranging from 6,700 feet to 11,300 feet. In addition, the Company is drilling deeper to the Strawn, Atoka and Mississippian intervals with positive results.

The Company believes the Spraberry field offers excellent opportunities to grow oil and gas production because of the numerous undeveloped drilling locations, many of which are reflected in the Company's proved undeveloped reserves. The

Spraberry field has the ability to improve incremental recovery rates through infill and deeper formation drilling, waterflood projects and horizontal drilling in certain formations while containing operating expenses and drilling costs through economies of scale and vertical integration of field services.

During 2012, the Company drilled 691 wells in the Spraberry field and its total acreage position now approximates 827,000 gross acres (707,000 net acres). The Company currently has 24 rigs operating in the Spraberry field, of which 15 are drilling vertical wells and nine are drilling horizontal Wolfcamp Shale wells. During 2013, the Company expects to drill approximately 290 vertical wells and 120 horizontal wells, with the horizontal wells being principally in the Wolfcamp Shale horizon. Excluding the southern Wolfcamp joint interest area, the Company expects to incur $1.2 billion of drilling capital in the Spraberry field during 2013.

In the horizontal Wolfcamp Shale play, the Company believes it has significant resource potential within its acreage based on its extensive geologic data covering the Wolfcamp A, B, C and D intervals and its drilling results to-date. The Company's horizontal drilling activity for 2013 will be focused on the southern part of the play where the Company expects to drill 86 horizontal Wolfcamp Shale wells and the northern part of the play where the Company expects to drill 30 to 40 horizontal wells.

The Company believes it also has significant horizontal potential within the northern portion of its acreage in the play. During the fourth quarter of 2012, the Company initiated horizontal Wolfcamp drilling activities to delineate the northern part of its Spraberry acreage position by drilling in Midland County. During 2013, the Company plans to also test the Wolfcamp Shale potential in Martin County and possibly Gaines County. Wells drilled in these areas are expected to benefit from greater original oil in place and higher reservoir pressures associated with deeper drilling depths. In addition, during 2013, the Company plans to drill several Spraberry shale and Jo Mill horizontal wells. The Company expects to utilize four horizontal rigs in its northern acreage during 2013 to delineate the area's resource potential.

The Company continues to drill vertically to deeper intervals in the Spraberry field below the Wolfcamp interval. This deeper drilling includes the Strawn, Atoka and Mississippian intervals. Production from these deeper intervals contributed to the Company's production growth during 2012. The 2013 drilling program reflects 90 percent of the wells being deepened below the Wolfcamp interval. Based on results to-date, the Company estimates that 85 percent of its Spraberry acreage position is prospective for the Strawn interval, that 40 percent to 50 percent of its acreage position is prospective for the Atoka interval and that the Mississippian interval is prospective in 20 percent of the Company's Spraberry acreage.

In the Spraberry interval, during 2012, the Company drilled two successful horizontal Jo Mill wells with lateral lengths of 2,628 and 2,178 feet. The Company is continuing to analyze the results of the two wells and plans to drill additional horizontal Jo Mill wells in 2013.

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 $1.7 billion. At closing Sinochem will pay $522.0 million in cash to Pioneer, before normal closing adjustments, and will pay the remaining $1.2 billion by carrying 75 percent of Pioneer's portion of future drilling and facilities costs attributable to the horizontal Wolfcamp Shale play. This transaction is expected to close during the second quarter of 2013, subject to governmental and third party approvals. The Company and Sinochem have agreed to a plan to drill 86 horizontal Wolfcamp Shale wells during 2013, 120 wells in 2014 and 165 wells in 2015. Associated therewith, the Company expects to incur $425.0 million of drilling and facilities capital during 2013. To the extent the joint interest partner elects to participate in any vertical wells that are drilled in the joint interest area after the December 1, 2012 effective date, the joint interest partner will receive its share of production and costs from the Wolfcamp and deeper horizons based on the anticipated reserve contribution from the Wolfcamp and deeper intervals relative to anticipated reserves from all completed intervals. Pioneer's and the joint interest owner's participation in vertical wells will be based on each party's interest without any drilling carry being applied. Pioneer will retain 100 percent of its vertical production in the joint interest area for wells drilled before the December 1, 2012 effective date.

The Company continues to expand 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 owns 15 drilling rigs and has five Company-owned vertical fracture stimulation fleets totaling 100,000 horsepower and two Company-owned horizontal fracture stimulation fleets totaling 70,000 horsepower currently operating in the Spraberry field. To support its growing 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, in early April 2012, the Company completed the acquisition of Premier Silica, which is expected to supply the Company's growing brown sand requirements for proppant that will be used for fracture stimulating wells in the vertical Spraberry and horizontal Wolfcamp Shale plays.

Mid-Continent

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's Hugoton properties are located on 268,000 gross acres (235,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,220 wells in the Hugoton field, approximately 1,000 of which it operates.

The Company operates substantially all of the gathering and processing facilities, including the Satanta plant, which processes the production from the Hugoton field. In January 2011, the Company sold a 49 percent interest in the Satanta plant to an unaffiliated third party for the third party's commitment to dedicate gas volumes to the Satanta plant. This agreement has increased the Satanta plant's processing volumes and is expected to increase its economic longevity. The Company is also exploring opportunities to process other gas production in the Hugoton area at the Satanta plant. By maintaining operatorship of the gathering and processing facilities, the Company is able to control the production, gathering, processing and sale of its Hugoton field gas and NGL production.

West Panhandle field. 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 1,365 BTU and is produced from approximately 867 wells on more than 333,000 gross acres (312,000 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 operated at or below vacuum conditions, Pioneer continually works to improve compressor and gathering system efficiency.

Raton Basin

The Raton Basin properties are located in the southeast portion of Colorado. The Company owns 212,000 gross acres (186,000 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. The Company owns the majority of the well servicing and fracture stimulation equipment that it utilizes in the Raton field, allowing it to control costs and insure availability.

South Texas Eagle Ford Shale and Edwards

The Company's drilling activities in the South Texas area during 2012 continued to be primarily focused on delineation and development of Pioneer's substantial acreage position in the Eagle Ford Shale play. The 2012 drilling program has been focused on liquids-rich drilling, with only 10 percent of the wells designated to hold strategic dry gas acreage.

The Company completed 137 horizontal Eagle Ford Shale wells during 2012, all of which were successful, with average lateral lengths of 5,700 feet and, on average, 13-stage fracture stimulations. The Company plans to incur $575 million of drilling capital and utilize 10 drilling rigs in 2013 to drill 134 wells. The Company plans to primarily use two Pioneer-owned fracture stimulation fleets during 2013.

The Company has also been testing the use of lower-cost white sand instead of ceramic proppant to fracture stimulate wells drilled in shallower areas of the field. The Company is expanding the use of white sand proppant to deeper areas of the field to further define its performance limits. Early well performance has been similar to direct offset ceramic-stimulated wells. The Company is continuing to monitor the performance of these wells and expects that greater than 50 percent of its 2013 drilling program will use lower-cost white sand proppant.

During June 2010, the Company entered into an Eagle Ford Shale joint venture transaction. Pursuant to the transaction, the Company entered into a purchase and sale agreement to sell 45 percent of its Eagle Ford Shale proved and unproved oil and gas properties to an unaffiliated third party for $212.0 million of cash proceeds. Under the terms of the transaction, the purchaser also paid 75 percent (representing $886.8 million) of the Company's defined exploration, drilling and completion costs attributable to the Eagle Ford Shale assets during the period from June 2010 through December 2012. As of December 31, 2012, the purchaser's obligation has been satisfied. The Company also sold a 49.9 percent member interest in EFS Midstream LLC ("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, to the

purchaser for $46.4 million of cash proceeds and deferred a $46.2 million associated net gain. The Company does not have voting control of EFS Midstream and does not consolidate its financial statements.
EFS Midstream is obligated to construct midstream assets in the Eagle Ford Shale area. Construction of the midstream assets is continuing, with the majority of the construction expected to be completed by the end of 2013. Eleven of the 13 planned central gathering plants were completed as of December 31, 2012. EFS Midstream is providing gathering, treating and transportation services for the Company during a 20-year contractual term. During 2011, EFS Midstream entered into a $300 million, five-year revolving credit facility that is being used to fund infrastructure investments that exceed its operating cash flows.

Table of Contents

Barnett Shale

The Company has accumulated 93,000 gross acres in the liquid-rich Barnett Shale Combo area in North Texas. In addition, the Company has acquired approximately 340 square miles of proprietary 3-D seismic covering its acreage, which it is using to high-grade future drilling location selections. The Company's total lease holdings in the Barnett Shale play now approximate 149,000 gross acres (114,000 net acres).

During the first half of 2012, the Company had two drilling rigs and one Pioneer-owned fracture stimulation fleet operating in the field. During August 2012, the Company reduced to one drilling rig as a result of lower NGL and gas prices. The Company drilled 57 Barnett Shale Combo wells during 2012.

During the third quarter of 2012, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas, retained a capital markets advisor and actively solicited offers from interested purchasers of the Barnett Shale field assets. Those efforts were unsuccessful in attracting binding offers under acceptable terms to the Company. Since the Company was unable to dispose of its Barnett Shale assets under acceptable terms, in December 2012, the Company decided to retain the assets; therefore, as of December 31, 2012, the Barnett Shale assets and liabilities no longer qualified as held for sale or discontinued operations.

During 2013, the Company plans to increase from one drilling rig to two drilling rigs early in the second quarter. The Company expects to drill 55 wells in 2013 and incur capital expenditures of $185.0 million.

Alaska

The Company owns a 70 percent working interest in, and is the operator of, the Oooguruk development project. Since inception, the Company has drilled 18 production wells and ten injection wells to develop this project. During the first quarter of 2012, the Company drilled an exploration well which was drilled from an onshore location to further evaluate the productivity of the Torok formation and the feasibility of future development expansion. The Company flow tested the well during April 2012 until production could no longer be transported along the ice road being utilized. The well had a gross initial production rate of approximately 2,000 barrels of oil per day. The well will be production tested again this winter pending permanent onshore production facilities, for which an onshore development front-end engineering design (FEED) study has been initiated. In September 2012, the Company entered into a contract for a drilling rig that is currently drilling a second onshore well in the Torok formation to further appraise its resource potential.

During the first quarter of 2012, the Company also completed its first successful mechanically diverted fracture stimulation of a Nuiqsut interval well from the Oooguruk development facilities. Gross initial production from the test was at a rate of 4,000 barrels of oil per day. Based on the success of this fracture stimulation, the Company plans to fracture stimulate four new wells this winter using a similar completion design.

During 2013, the Company expects to incur capital expenditures of $190.0 million in Alaska to continue development with a one rig program at Oooguruk, mechanically fracture stimulate four wells this winter on the island drill site and to complete the other appraisal well in the Torok formation from the onshore drilling location.

International

During 2012, the Company's international operations were entirely located in offshore South Africa and during 2011, the Company's international operations were located in Tunisia and offshore South Africa. During August 2012 and February 2011, the Company completed the sale of Pioneer South Africa and Pioneer Tunisia, respectively, to different unaffiliated third parties. 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 and Pioneer Tunisia. As a result of these sales, 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, 2012, 2011 and 2010. 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.

Table of Contents

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. A substantial or extended decline in oil or gas prices or poor drilling results 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 2012, 2011 and 2010. 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 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 reserve volume tables.

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2012				
	United States			South Africa	Total
	Spraberry Field	Raton Field	Total		
Production information:					
Annual sales volumes:					
Oil (MBBLs)	16,096	—	22,928	157	23,085
NGLs (MBBLs)	4,451	—	10,913	—	10,913
Gas (MMCF)	21,345	54,822	138,483	3,784	142,267
Total (MBOE)	24,104	9,137	56,921	787	57,708
Average daily sales volumes:					
Oil (BBLs)	43,978	—	62,645	428	63,073
NGLs (BBLs)	12,160	—	29,816	—	29,816
Gas (MCF)	58,319	149,787	378,369	10,340	388,709
Total (BOE)	65,858	24,965	155,522	2,151	157,673
Average prices, including hedge results and amortization of deferred VPP revenue (a):					
Oil (per BBL)	$90.57	$—	$90.89	$108.62	$91.01
NGL (per BBL)	$32.23	$—	$33.75	$—	$33.75
Gas (per MCF)	$2.58	$2.41	$2.60	$8.50	$2.75
Revenue (per BOE)	$68.72	$14.48	$49.40	$62.48	$49.57
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):					
Oil (per BBL)	$87.95	$—	$89.19	$108.62	$89.32
NGL (per BBL)	$32.23	$—	$33.75	$—	$33.75
Gas (per MCF)	$2.58	$2.41	$2.60	$8.50	$2.75
Revenue (per BOE)	$66.97	$14.48	$48.71	$62.48	$48.90
Average costs (per BOE):					
Production costs:					
Lease operating	$11.34	$6.47	$8.53	$2.86	$8.46
Third-party transportation charges	$0.17	$3.12	$1.31	$—	$1.29
Net natural gas plant/gathering	$(0.49)	$1.82	$0.47	$—	$0.47
Workover	$1.71	$—	$0.85	$—	$0.84
Total	$12.73	$11.41	$11.16	$2.86	$11.06
Production and ad valorem taxes:					
Ad valorem	$1.78	$0.17	$1.26	$—	$1.24
Production	$3.47	$0.11	$2.04	$—	$2.01
Total	$5.25	$0.28	$3.30	$—	$3.25
Depletion expense	$15.58	$19.52	$13.61	$—	$13.42

(a) The Company records the amortization of deferred VPP revenue at a field level but does not record the results of its hedging activities at a field level. As of December 31, 2012, the Company has no further obligation to deliver oil under the VPP obligation.

39

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2011					
	United States			South Africa	Tunisia	Total
	Spraberry Field	Raton Field	Total			
Production information:						
Annual sales volumes:						
Oil (MBBLs)	10,011	—	14,825	193	201	15,219
NGLs (MBBLs)	3,844	—	8,208	—	—	8,208
Gas (MMCF)	15,899	58,601	125,516	7,508	181	133,205
Total (MBOE)	16,505	9,767	43,953	1,445	229	45,627
Average daily sales volumes:						
Oil (BBLs)	27,428	—	40,618	530	547	41,695
NGLs (BBLs)	10,530	—	22,487	—	—	22,487
Gas (MCF)	43,559	160,550	343,879	20,570	496	364,945
Total (BOE)	45,218	26,758	120,418	3,958	630	125,006
Average prices, including hedge results and amortization of deferred VPP revenue (a):						
Oil (per BBL)	$95.93	$—	$96.60	$108.14	$99.03	$96.78
NGL (per BBL)	$42.38	$—	$46.27	$—	$—	$46.27
Gas (per MCF)	$3.44	$3.81	$3.84	$7.62	$13.04	$4.07
Revenue (per BOE)	$71.37	$22.86	$52.19	$54.09	$96.29	$52.48
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):						
Oil (per BBL)	$91.44	$—	$91.35	$108.14	$99.03	$91.67
NGL (per BBL)	$42.38	$—	$46.27	$—	$—	$46.27
Gas (per MCF)	$3.44	$3.81	$3.84	$7.62	$13.04	$4.07
Revenue (per BOE)	$68.65	$22.86	$50.42	$54.09	$96.29	$50.77
Average costs (per BOE):						
Production costs:						
Lease operating	$10.40	$6.49	$8.08	$2.35	$7.61	$7.90
Third-party transportation charges	$—	$3.01	$1.12	$—	$1.91	$1.22
Net natural gas plant/gathering	$(1.45)	$2.15	$0.15	$—	$—	$0.14
Workover	$1.74	$—	$0.82	$—	$(0.27)	$0.78
Total	$10.69	$11.65	$10.17	$2.35	$9.25	$10.04
Production and ad valorem taxes:						
Ad valorem	$1.73	$0.41	$1.24	$—	$—	$1.20
Production	$3.87	$0.31	$2.11	$—	$—	$2.04
Total	$5.60	$0.72	$3.35	$—	$—	$3.24
Depletion expense	$11.41	$14.46	$12.55	$29.00	$—	$13.01

(a)

The Company records the amortization of deferred VPP revenue at a field level but does not record the results of its hedging activities at a field level.

PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2010					
	United States			South Africa	Tunisia	Total
	Spraberry Field	Raton Field	Total			
Production information:						
Annual sales volumes:						
Oil (MBBLs)	6,314	—	10,297	225	1,781	12,303
NGLs (MBBLs)	3,725	—	7,203	—	—	7,203
Gas (MMCF)	14,242	62,311	122,369	10,862	1,040	134,271
Total (MBOE)	12,413	10,385	37,895	2,035	1,954	41,885
Average daily sales volumes:						
Oil (BBLs)	17,300	—	28,211	616	4,880	33,707
NGLs (BBLs)	10,206	—	19,736	—	—	19,736
Gas (MCF)	39,020	170,716	335,256	29,760	2,849	367,865
Total (BOE)	34,009	28,453	103,823	5,576	5,355	114,754
Average prices, including hedge results and amortization of deferred VPP revenue (a):						
Oil (per BBL)	$91.53	$—	$90.56	$78.07	$78.42	$88.57
NGL (per BBL)	$33.11	$—	$38.14	$—	$—	$38.14
Gas (per MCF)	$3.41	$4.20	$4.18	$6.20	$11.25	$4.40
Revenue (per BOE)	$60.40	$25.19	$45.34	$41.74	$77.46	$46.67
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):						
Oil (per BBL)	$77.24	$—	$74.21	$78.07	$78.42	$74.89
NGL (per BBL)	$33.11	$—	$37.12	$—	$—	$37.12
Gas (per MCF)	$3.41	$4.20	$4.15	$6.20	$11.25	$4.37
Revenue (per BOE)	$53.14	$25.19	$40.61	$41.74	$77.46	$42.39
Average costs (per BOE):						
Production costs:						
Lease operating	$11.40	$6.11	$7.74	$0.68	$4.98	$7.28
Third-party transportation charges	$—	$2.35	$0.87	$—	$1.50	$0.86
Net natural gas plant/gathering	$(1.66)	$1.93	$0.08	$—	$—	$0.08
Workover	$1.88	$0.07	$0.92	$—	$0.36	$0.85
Total	$11.62	$10.46	$9.61	$0.68	$6.84	$9.07
Production and ad valorem taxes:						
Ad valorem	$2.30	$0.46	$1.49	$—	$—	$1.35
Production	$3.53	$0.52	$1.47	$—	$—	$1.33
Total	$5.83	$0.98	$2.96	$—	$—	$2.68
Depletion expense	$9.02	$14.39	$12.40	$36.50	$12.07	$13.56

(a)

The Company records the amortization of deferred VPP revenue at a field level but does not record the results of its hedging activities at a field level.

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. As of December 31, 2012, the Company owned interests in two gross wells containing multiple completions.

The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2012, 2011 and 2010:

PRODUCTIVE WELLS

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
December 31, 2012	6,703	5,306	12,009	5,960	4,755	10,715
December 31, 2011	6,111	5,004	11,115	5,525	4,505	10,030
December 31, 2010	5,566	4,842	10,408	4,779	4,350	9,129

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2012:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
Onshore	1,690,423	1,437,950	1,492,469	997,269	307,301
Offshore	—	—	—	—	5,000
	1,690,423	1,437,950	1,492,469	997,269	312,301

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2012:

	Acres Expiring (a)	
	Gross	Net
2013	153,898	103,907
2014	195,783	137,503
2015	181,666	129,027
2016	780,814	494,264
2017	147,048	102,838
Thereafter	33,260	29,730
Total	1,492,469	997,269

(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 2012, 2011 and 2010 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 Year Ended December 31,			Net Wells Year Ended December 31,		
	2012	2011	2010	2012	2011	2010
Productive wells:						
Development	659	725	436	595	661	380
Exploratory	223	167	39	144	115	24
Dry holes:						
Development	10	11	3	6	10	3
Exploratory	6	1	3	6	1	1
Total	898	904	481	751	787	408
Success ratio (a)	98 %	99 %	99 %	98 %	99 %	99 %

(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, 2012:

	Gross Wells	Net Wells
Development	140	130
Exploratory	60	42
Total	200	172

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 such 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

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 $.04 per share during each of the first and third quarters of the years ended December 31, 2012 and 2011. 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, 2012 and 2011:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2012			
Fourth quarter	$110.67	$99.75	$—
Third quarter	$115.69	$82.18	$0.04
Second quarter	$117.05	$77.41	$—
First quarter	$119.19	$90.26	$0.04
Year ended December 31, 2011			
Fourth quarter	$97.10	$58.63	$—
Third quarter	$99.64	$65.73	$0.04
Second quarter	$106.07	$82.41	$—
First quarter	$104.29	$85.90	$0.04

On February 8, 2013, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $128.97 per share.

As of February 8, 2013, the Company's common stock was held by 14,429 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, 2012:

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 2012	532	$104.40	—	
November 2012	—	$—	—	
December 2012	64,373	$102.41	—	
Total	64,905	$102.43	—	$ —

(a) Consists of shares withheld to satisfy tax withholding on employees' share-based awards.

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, 2012 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,				
	2012	2011	2010	2009	2008
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues (a)	$2,811.7	$2,294.1	$1,718.3	$1,402.4	$1,893.4
Total revenues (b)	$3,228.3	$2,751.5	$2,381.7	$1,290.4	$1,920.1
Total costs and expenses (c)	$2,948.3	$2,095.1	$1,600.1	$1,515.6	$1,675.3
Income (loss) from continuing operations	$187.7	$458.8	$511.9	$(142.0)	$144.8
Income from discontinued operations, net of tax (d)	$55.1	$423.2	$134.1	$99.7	$86.8
Net income (loss) attributable to common stockholders	$192.3	$834.5	$605.2	$(52.1)	$210.0
Income (loss) from continuing operations attributable to common stockholders per share:					
Basic	$1.10	$3.45	$4.00	$(1.33)	$1.02
Diluted	$1.07	$3.39	$3.96	$(1.33)	$1.02
Net income (loss) attributable to common stockholders per share:					
Basic	$1.54	$7.01	$5.14	$(0.46)	$1.76
Diluted	$1.50	$6.88	$5.08	$(0.46)	$1.76
Dividends declared per share	$0.08	$0.08	$0.08	$0.08	$0.30
Balance Sheet Data (as of December 31):					
Total assets	$13,069.0	$11,447.2	$9,679.1	$8,867.3	$9,161.8
Long-term obligations	$6,166.9	$4,726.5	$4,683.9	$4,653.0	$4,787.2
Total stockholders' equity	$5,867.3	$5,651.1	$4,226.0	$3,643.0	$3,679.6

(a) The Company's oil and gas revenues for 2012, as compared to those of 2011, increased by $517.6 million (or 23 percent) due to increases in oil, NGL, and gas sales volumes. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussions about oil and gas revenues and factors impacting the comparability of such revenues.

(b) The Company recognized $330.3 million of net derivative gains in its total revenues for 2012, including $65.4 million of noncash MTM losses, as compared to $392.8 million of net derivative gains during 2011, including $225.5 million of noncash MTM gains. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Notes B and E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information about the Company's derivative contracts and associated accounting methods. The Company also recognized $138.9 million of net hurricane activity gains during 2010, primarily associated with East Cameron 322 insurance recoveries, and $17.3 million of net hurricane activity charges during 2009. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the East Cameron 322 reclamation and abandonment project.

(c) During 2012, the Company recorded $604.4 million of pretax noncash impairment and abandonment charges to reduce the carrying value of its Barnett Shale field assets. During 2011, the Company recorded an impairment charge of $354.4 million related to its Edwards and Austin Chalk net assets in South Texas. See Note D of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." During

2009 and 2008, the Company recorded impairment charges of $21.1 million and $89.8 million, respectively, to reduce its Uinta/Piceance field's carrying value.

(d) During December 2011, the Company committed to a plan to divest Pioneer South Africa and in August 2012, the Company completed the sale of Pioneer South Africa for net cash proceeds of $15.9 million, resulting in a pretax gain of $28.6 million. During December 2010, the Company committed to a plan to sell Pioneer Tunisia and in February 2011 completed the sale of the Company's share holdings in Pioneer Tunisia to an unaffiliated party for net cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a pretax gain of $645.2 million. During 2010, the Company received $35.3

45

million of interest on excess royalties paid during the period from January 1, 2003 through December 31, 2005 on oil and gas production from its deepwater Gulf of Mexico properties, which were sold in 2006. During 2009, the Company recorded $119.3 million of pretax income for the recovery of the excess royalties previously mentioned and a $17.5 million pretax gain, primarily from the sale of substantially all of its Gulf of Mexico shelf properties. The results of operations of these properties, and certain other properties sold during the periods presented are classified as discontinued operations in accordance with GAAP. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's discontinued operations.

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 2012 included the following highlights:

- Earnings attributable to common stockholders was $192.3 million ($1.50 per diluted share) for the year ended December 31, 2012, as compared to $834.5 million ($6.88 per diluted share) in 2011. The decrease in earnings attributable to common stockholders is primarily due to:
  - a $368.0 million decrease in income from discontinued operations, net of associated income taxes, primarily attributable to a $645.2 million pretax gain on the sale of Pioneer Tunisia during February 2011;
  - a $231.9 million increase in DD&A, primarily due to a 29 percent increase in sales volumes;
  - a $188.5 million increase in oil and gas production costs, primarily due to increases in lease operating expenses as a result of higher sales volumes and inflation of oilfield service costs;
  - a $178.2 million increase in impairment provisions related to a $532.6 million impairment in the Barnett Shale field associated with reductions in management's commodity 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) compared to a $354.4 million impairment related to Edwards and Austin Chalk net assets in South Texas in 2011;
  - an $85.0 million increase in exploration and abandonments expense, primarily due to impairment of unproved gas prospects in the Barnett Shale field;
  - a $62.5 million decrease in net derivative gains, primarily due to reduced interest rate derivative gains during 2012; and
  - a $55.1 million increase in general and administrative expenses due to increases in compensation expense related to a 16 percent increase in office employees supporting the Company's capital expansion initiatives, partially offset by
  - a $517.6 million increase in oil and gas revenues as a result of increased sales volumes, partially offset by lower average sales prices; and
  - a $105.3 million decrease in income tax provision.
- Daily sales volumes from continuing operations increased on a BOE basis by 29 percent to 155,522 BOEPD during 2012, as compared to 120,418 BOEPD during 2011, primarily due to the success of the Company's drilling programs;
- Average reported oil, NGL and gas prices from continuing operations decreased during 2012 to $90.89 per BBL, $33.75 per BBL and $2.60 per MCF, respectively, as compared to respective average reported prices of $96.60 per BBL, $46.27 per BBL and $3.84 per MCF during 2011;
- Average oil and gas production costs per BOE from continuing operations increased during 2012 to $11.16 as compared to per BOE costs of $10.17 during 2011, primarily due to increases in lease operating expenses, third party transportation charges and net natural gas plant charges. The increase in lease operating expenses is primarily due to an increase in salt water disposal costs (principally comprised of water hauling fees) during 2012. The increase in third-party transportation costs is primarily due to gathering, treating and transportation costs associated with increasing sales volumes in the Eagle Ford Shale field. Net natural gas plant charges increased primarily as a result of lower gas and NGL prices being realized on third-party volumes that are retained as processing fees in Company-owned facilities. See "Results of Operations" below for more information about changes in production costs;
- Net cash provided by operating activities increased by $307.9 million, or 20 percent, to $1.8 billion for 2012, as compared to $1.5 billion during 2011, primarily due to the increases in oil and gas sales volumes and realized derivative gains;
- During April 2012, the Company acquired 100 percent of the share capital of Industrial Sands Holding Company and its wholly-owned subsidiary, Premier Silica. Premier Silica's core business is the operation of mines and processing facilities that produce, process and sell sand, primarily to upstream oil and gas companies for proppant used in the fracture stimulation of oil and gas wells in the United States. The aggregate purchase price of Premier Silica was

$297.1 million and was funded from available cash and borrowings under the Company's credit facility;

- During May 2012, the Company was rated investment grade by a second credit rating agency after having been similarly rated investment grade by another credit rating agency during 2011;
- During the December 2012, the Company entered into the First Amendment to Second Amended and Restated 5-Year Credit Agreement (the "Credit Facility") with a syndicate of financial institutions that increased the Company's borrowing capacity under the Credit Facility to $1.5 billion and extended its maturity to December 2017;

- Long-term debt increased by $1.2 billion and the Company's cash and cash equivalents decreased by $308.1 million during 2012; and
- As of December 31, 2012, the Company's net debt to book capitalization was 37 percent, as compared to 26 percent as of December 31, 2011.

During the first quarter of 2013, the following significant events occurred:

- 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 $1.7 billion. At closing, Sinochem will pay $522.0 million in cash to Pioneer, before normal closing adjustments, and will pay the remaining $1.2 billion by carrying 75 percent of Pioneer's portion of future drilling and facilities costs attributable to the horizontal Wolfcamp Shale play. This transaction is expected to close during the second quarter of 2013, subject to governmental and third party approvals.
- In January and February 2013, holders of $240.6 million principal amount of the Company's 2.875% Convertible Senior Notes due 2038 (the "Convertible Senior Notes") exercised their right to convert their Convertible Senior Notes into cash and shares of the Company's common stock. In general, upon conversion of a Convertible Senior Note, the holder will receive cash equal to the principal amount of the Convertible Senior Note and shares of the Company's common stock for the Convertible Senior Note's conversion value in excess of the principal amount. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Convertible Senior Notes.

First Quarter 2013 Outlook

Based on current estimates, the Company expects that first quarter 2013 production will average 165,000 to 170,000 BOEPD.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $14.00 to $16.00 per BOE, based on current NYMEX strip prices for oil and gas. DD&A expense is expected to average $13.50 to $15.50 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 $60 million to $65 million. Interest expense is expected to be $53 million to $58 million, and other expense is expected to be $25 million to $35 million. Accretion of discount on asset retirement obligations is expected to be $2 million to $4 million.

Noncontrolling interest in consolidated subsidiaries' net income, excluding noncash derivative MTM adjustments, is expected to be $8 million to $11 million, primarily reflecting the public ownership in Pioneer Southwest.

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 $2 million to $7 million and are primarily attributable to state taxes.

2013 Capital Budget

Pioneer's capital program for 2013 totals $3.0 billion, consisting of $2.75 billion for drilling operations, including budgeted land capital for existing assets, and $240 million for other property, plant and equipment. The 2013 budget excludes acquisitions, asset retirement obligations, capitalized interest and geological and geophysical general and administrative expense and assumes the aforementioned sale of a 40 percent interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field will close on or about June 1, 2013.

The 2013 drilling capital of $2.75 billion continues to be focused on oil- and liquids-rich drilling, with 81 percent of the capital allocated to the Spraberry field, including the horizontal Wolfcamp Shale play, and the Eagle Ford Shale play. Following is a breakdown of the forecasted spending by asset area:

- Spraberry field - $1.65 billion, including (i) $425 million for drilling and facilities capital in the southern Wolfcamp joint interest area, (ii) $400 million of horizontal appraisal drilling capital associated with the Company's planned two-year $1 billion appraisal program for its northern Wolfcamp/Spraberry acreage, (iii) $625 million for vertical drilling and (iv) $200 million of infrastructure additions and automation projects;

- Eagle Ford Shale – $575 million;
- Barnett Shale Combo play – $185 million;
- Alaska – $190 million; and

- Other spending – $150 million, including land capital for existing assets.

Pioneer's budgeted expenditures for other property, plant and equipment in 2013 include:

- Buildings and other facilities – $145 million;
- Brady sand mine expansion – $70 million; and
- Vertical integration capital – $25 million.

The 2013 capital budget is expected to be funded from a combination of cash and cash equivalents, operating cash flow, borrowings under the Credit Facility, proceeds from the sale of joint interests or nonstrategic assets, and issuances of debt or equity securities.

Acquisitions

During 2012, 2011 and 2010, the Company spent $157.5 million, $131.9 million and $181.6 million, respectively, to acquire primarily undeveloped acreage for future exploitation and exploration activities. The 2012 acquisitions primarily increased the Company's acreage positions in the West Texas Spraberry field. The 2011 and 2010 acquisitions primarily increased the Company's acreage positions in the South Texas Eagle Ford Shale play, Barnett Shale play and West Texas Spraberry field. Additionally, in 2012 the Company acquired Premier Silica for $297.1 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

Barnett Shale. During the third quarter of 2012, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. In connection therewith, the Company classified its (i) Barnett Shale assets and liabilities as discontinued operations held for sale in the Company's consolidated balance sheet as of September 30, 2012, and (ii) Barnett Shale results of operations as income or loss from discontinued operations, net of tax, in the consolidated statements of operations for the three and nine months ended September 30, 2012 and 2011.

The Company retained a capital markets advisor during the third quarter of 2012 and actively solicited offers from interested purchasers of the Barnett Shale field assets. Those efforts were unsuccessful in attracting binding offers under acceptable terms to the Company. Since the Company was unable to dispose of its Barnett Shale field assets under acceptable terms, in December 2012, the Company decided to retain the assets; therefore, the Barnett Shale assets and liabilities no longer qualified as held for sale or discontinued operations. Accordingly, all amounts related to the Barnett Shale that were previously reported as (i) discontinued operations held for sale were reclassified to continuing operations at December 31, 2012, (ii) results from the Barnett Shale operations were recorded to continuing operations for the quarter ended December 31, 2012 and results included in discontinued operations were reclassified to income from continuing operations for the nine months ended September 30, 2012, and (iii) amounts in periods prior to 2012 that were reflected in discontinued operations were reclassified to continuing operations. 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 discontinued operations.

Pioneer South Africa. During December 2011, the Company committed to a plan to exit South Africa and initiated a process to divest Pioneer South Africa. The assets and liabilities of Pioneer South Africa are classified as discontinued operations held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2011. During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60.0 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 net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a pretax gain of $28.6 million. Pioneer South Africa's historical results of operations, and the related gain recorded on the disposition of Pioneer South Africa, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Pioneer Tunisia. During December 2010, the Company committed to a plan to sell Pioneer Tunisia. In February 2011 the Company sold its share holdings in Pioneer Tunisia for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a pretax gain of $645.2 million. Pioneer Tunisia's historical results of operations, and the related gain recorded on the disposition of Pioneer Tunisia, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Eagle Ford Shale. In June 2010, the Company entered into an Eagle Ford Shale joint venture. Associated therewith, the Company sold 45 percent of its Eagle Ford Shale proved and unproved oil and gas properties to an unaffiliated third party for $212.0 million of cash proceeds. Under the terms of the transaction, the purchaser also paid 75 percent (representing $886.8

million) of the Company's defined exploration, drilling and completion costs attributable to the Eagle Ford Shale assets during the period from June 2010 through December 2012.

Uinta/Piceance. During the first half of 2010, the Company sold certain proved and unproved oil and gas properties in the Uinta/Piceance area for net proceeds of $11.8 million and the assumption by the purchaser of certain asset retirement obligations, resulting in a pretax gain of $17.3 million.

Results of Operations

Oil and gas revenues. Oil and gas revenues from continuing operations totaled $2.8 billion, $2.3 billion and $1.7 billion during 2012, 2011 and 2010, respectively.

The increase in 2012 oil and gas revenues relative to 2011 is reflective of 54 percent, 33 percent and 10 percent increases in oil, NGL and gas sales volumes, respectively. Partially offsetting the effects of these production increases were declines of six percent, 27 percent and 32 percent in average reported oil, NGL and gas prices, respectively.

The increase in 2011 oil and gas revenues relative to 2010 is reflective of seven percent and 21 percent increases in average reported oil and NGL prices, respectively and 44 percent, 14 percent and three percent increases in oil, NGL, and gas sales volumes, respectively. These increases were partially offset by an eight percent decrease in average reported gas prices.

The following table provides average daily sales volumes from continuing operations for 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Oil (BBLs)	62,645	40,618	28,211
NGLs (BBLs)	29,816	22,487	19,736
Gas (MCF)	378,369	343,879	335,256
Total (BOE)	155,522	120,418	103,823

Average daily BOE sales volumes in 2012 and 2011 increased by 29 percent and 16 percent, respectively, as compared to the daily sales volumes in the respective prior years, principally due to the Company's successful drilling programs and declines in scheduled VPP deliveries. Oil volumes delivered under the Company's VPPs decreased by six percent and 45 percent, respectively, during 2012 and 2011. All VPP production volumes have been delivered as of December 31, 2012 and there are no further obligations under the VPP contracts.

Production growth for 2012, as compared to 2011, was negatively impacted by gas processing capacity limitations in the Spraberry field as a result of wet gas production for the Company and other industry participants growing faster than anticipated. The gas processing capacity limitations resulted in reduced recoveries of ethane, negatively impacting average 2012 sales volumes by approximately 1,450 BOEPD. New Spraberry field gas processing facilities are being built and are expected to be on production in April of 2013.

The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Oil (BBLs):			
South Africa	428	530	616
Tunisia	—	547	4,880
Worldwide	428	1,077	5,496
Gas (MCF):			
South Africa	10,340	20,570	29,760
Tunisia	—	496	2,849
Worldwide	10,340	21,066	32,609
Total (BOE):			
South Africa	2,151	3,958	5,576
Tunisia	—	630	5,355
Worldwide	2,151	4,588	10,931

In South Africa, sales volumes in 2012 declined by 46 percent from 2011 primarily due to the sale of Pioneer South Africa during August 2012 compared to a full year of production in 2011.

The oil, NGL and gas prices that the Company reports are based on the market prices received for the commodities adjusted for transfers of the Company's deferred hedge gains and losses from the effective portions of the discontinued deferred hedges included in accumulated other comprehensive income (loss) – net deferred hedge gains (losses), net of tax ("AOCI – Hedging") and the amortization of deferred VPP revenue. See "Derivative activities" and "Deferred revenue" discussion below for additional information regarding the Company's cash flow hedging activities and the amortization of deferred VPP revenue.

The following table provides average reported prices from continuing operations (including deferred hedge gains and losses and the amortization of deferred VPP revenue) and average realized prices from continuing operations (excluding deferred hedge gains and losses and the amortization of deferred VPP revenue) for 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Average reported prices:			
Oil (per BBL)	$90.89	$96.60	$90.56
NGL (per BBL)	$33.75	$46.27	$38.14
Gas (per MCF)	$2.60	$3.84	$4.18
Total (per BOE)	$49.40	$52.19	$45.34
Average realized prices:			
Oil (per BBL)	$89.19	$91.35	$74.21
NGL (per BBL)	$33.75	$46.27	$37.12
Gas (per MCF)	$2.60	$3.84	$4.15
Total (per BOE)	$48.71	$50.42	$40.61

Derivative activities. 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. Effective February 1, 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 February 1, 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.

The following table summarizes the transfers of deferred hedge gains and losses associated with oil, NGL and gas cash flow hedges from AOCI – Hedging to oil, NGL and gas revenues for the years ending December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Increase (decrease) to oil revenue from AOCI - Hedging transfers	$(3,156)	$32,918	$78,052
Increase to NGL revenue from AOCI - Hedging transfers	—	—	7,297
Increase to gas revenue from AOCI - Hedging transfers	—	—	3,691
Total	$(3,156)	$32,918	$89,040

Deferred revenue. During 2012, 2011 and 2010, the Company's amortization of deferred VPP revenue increased annual oil revenues by $42.1 million, $45.0 million and $90.2 million, respectively. All VPP production volumes have been delivered and there are no further obligations under VPP contracts or deferred revenue as of December 31, 2012. See the revenue recognition section of Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's deferred revenue.

Interest and other income. The Company's interest and other income from continuing operations totaled $28.3 million, $66.9 million and $57.0 million during 2012, 2011 and 2010, respectively. The $38.6 million decrease during 2012, as compared to 2011, is primarily attributable to a $27.9 million decrease in third-party income from vertical integration services, primarily due to increases in costs of services and idle equipment during the fourth quarter of 2012 and a $9.6 million decrease in Alaskan Petroleum Production Tax ("PPT") credit recoveries. The $9.9 million increase during 2011, as compared to 2010, is primarily attributable to a $15.8 million increase in third-party income associated with vertical integration services and a $2.7 million increase in equity earnings from EFS Midstream, partially offset by an $8.7 million decrease in PPT credit recoveries.

Derivative gains (losses), net. The following table summarizes the Company's net derivative gains or losses for the years ending December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Unrealized changes in fair value:			
Oil derivative gains	$217,765	$68,376	$41,094
NGL derivative gains	1,209	10,243	10,690
Gas derivative gains (losses)	(290,058)	179,787	277,585
Diesel derivative gains (losses)	(270)	270	—
Marketing derivative losses	(22)	—	—
Interest rate derivative gains (losses)	5,930	(33,206)	35,040
Total unrealized derivative gains (losses), net (a)	(65,446)	225,470	364,409
Cash settled changes in fair value:			
Oil derivative gains (losses)	4,139	(36,664)	(27,305)
NGL derivative gains (losses)	13,403	(15,418)	(7,180)
Gas derivative gains	402,981	183,010	119,417
Diesel derivative gains	3,497	67	—
Marketing derivative gains (losses)	36	(17)	—
Interest rate derivative gains (losses)	(28,359)	36,304	(907)
Total cash derivative gains, net	395,697	167,282	84,025
Total derivative gains, net	$330,251	$392,752	$448,434

(a) Unrealized changes in fair value are subject to continuing market risk.

Gain (loss) on disposition of assets. The Company recorded net gains of $58.1 million and $19.1 million during 2012 and 2010, respectively, and a net loss on the disposition of assets of $3.6 million during 2011.

During 2012, the Company recorded a $12.6 million pretax gain on the sale of its interest in the Cosmopolitan Unit in the Cook Inlet of Alaska and a $42.6 million pretax gain on the sale of a portion of its interest in an unproved oil and gas property in the Eagle Ford Shale field. During 2011, the net loss was primarily associated with losses on the sales of excess materials and supplies inventory, partially offset by gains on the sale of certain unproved properties. During 2010, the Company recorded a $17.3 million net gain associated with the sale of proved and unproved oil and gas properties in the Uinta/Piceance area and a $6.0 million net gain associated with the Eagle Ford Shale joint venture transaction, partially offset by net losses primarily associated with the sale of excess lease and well equipment inventory.

Hurricane activity, net. The Company recorded net hurricane activity gains of $1.5 million and $138.9 million during 2011 and 2010. The Company did not record any hurricane activity in 2012. As a result of Hurricane Rita in September 2005, the Company's East Cameron 322 facility, located on the Gulf of Mexico shelf, was completely destroyed. Operations to reclaim and abandon the East Cameron 322 facility began in 2006 and were completed during 2011. In 2007, the Company commenced legal actions against its insurance carriers regarding policy coverage issues for the cost of reclamation and abandonment of the East Cameron 322 facility. During the fourth quarter of 2010, the Company and the insurance carriers agreed to settle an insurance policy dispute, resulting in an additional payment to the Company of $140.1 million during November 2010. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's East Cameron platform facilities reclamation and abandonment activities.

Oil and gas production costs. The Company's oil and gas production costs from continuing operations totaled $635.6 million, $447.1 million and $364.8 million during 2012, 2011 and 2010, 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, 2012 increased by 10 percent as compared to 2011. The increase in production costs per BOE during 2012 is primarily reflective of increases in lease operating expenses, third-party transportation charges and net natural gas plant/gathering charges. Lease operating costs increased during 2012 primarily due to a $0.51 per BOE increase in salt water disposal costs (principally comprised of water hauling fees). The $0.19 per BOE increase in third-party transportation charges during 2012 is primarily due to gathering, treating and transportation costs associated with increasing sales volumes from the Company's successful drilling program in the Eagle Ford Shale field. Net natural gas plant charges increased by $0.32 per BOE during 2012, primarily due to a reduction in third-party revenues from processing third-party gas volumes in Company-owned facilities as a result of lower gas and NGL prices being realized on the volumes retained as a processing fee.

During 2011, total production costs per BOE increased by six percent as compared to 2010. The increase in production costs per BOE is primarily due to (i) increased third-party transportation and processing charges associated with increasing Eagle Ford Shale production, (ii) repairs associated with severe winter weather disruptions encountered during the first quarter of 2011 and (iii) inflation in well servicing costs, partially offset by reductions in VPP delivery commitments and decreased workover costs.

The following table provides the components of the Company's total production costs per BOE for 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Lease operating expenses	$8.53	$8.08	$7.74
Third-party transportation charges	1.31	1.12	0.87
Net natural gas plant/gathering charges	0.47	0.15	0.08
Workover costs	0.85	0.82	0.92
Total production costs	$11.16	$10.17	$9.61

Production and ad valorem taxes. The Company recorded production and ad valorem taxes of $187.8 million during 2012, as compared to $147.7 million and $112.1 million for 2011 and 2010, respectively. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During 2012, the Company's production taxes per BOE decreased by three percent as compared to 2011, primarily reflecting the impact of lower oil and NGL prices on production taxes. On a per BOE basis, ad valorem taxes increased two percent as compared to 2011. During 2011, the Company's production taxes per BOE increased 44 percent over 2010, primarily reflecting the impact of higher oil and NGL prices on production taxes, while ad valorem taxes decreased by 17 percent, which is primarily a result of an increase in sales volumes from new wells first brought on production during 2011.

Table of Contents

The following table provides the Company's production and ad valorem taxes per BOE from continuing operations and total production and ad valorem taxes per BOE from continuing operations for 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Production taxes	$2.04	$2.11	$1.47
Ad valorem taxes	1.26	1.24	1.49
Total ad valorem and production taxes	$3.30	$3.35	$2.96

Depletion, depreciation and amortization expense. The Company's total DD&A expense from continuing operations was $810.2 million ($14.23 per BOE), $578.3 million ($13.16 per BOE), and $499.9 million ($13.19 per BOE) for 2012, 2011 and 2010, respectively. Depletion expense on oil and gas properties, the largest component of DD&A expense, was $13.61, $12.55 and $12.40 per BOE during 2012, 2011 and 2010, respectively.

During 2012, the eight percent increase in per BOE depletion expense was primarily due to (i) increased drilling expenditures on proved undeveloped locations, primarily in the Spraberry field and (ii) declines in proved gas reserves due to lower first-day-of-the-month gas prices during the 12-month period ending on December 31, 2012, partially offset by (iii) the impairment effects of reducing carrying values of the Barnett Shale field and the South Texas Edwards Trend/Austin Chalk fields during 2012 and 2011, respectively (see the discussion below for more information on the Company's impairment charges).

During 2011, the one percent increase in per BOE depletion expense was primarily due to modest inflation in drilling costs in the Spraberry field in West Texas and the Barnett Shale field, partially offset by the cost containment associated with employed integrated services and increasing production in the Eagle Ford Shale play where portions of the Company's drilling costs were carried by a third party.

Impairment of oil and gas properties and other long-lived assets. The Company performs assessments of its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable.

Management's commodity price outlooks represent longer-term outlooks that are developed based on observable third-party futures price outlooks as of a measurement date ("Management's Price Outlooks"). During 2012 and 2011, declines in Management's Price Outlooks provided indications of possible impairment of the Company's predominantly dry gas properties in the Edwards Trend and Austin Chalk fields in South Texas, the Barnett Shale field in North Texas and the Raton field in southeastern Colorado. As a result of management's assessments, during 2012 and 2011, the Company recognized pretax noncash impairment charges of $532.6 million and $354.4 million to reduce the carrying values of the Barnett Shale field and the South Texas Edwards Trend/Austin Chalk fields, respectively, to their estimated fair values.

The Company's estimates of undiscounted future net cash flows attributable to the Raton field's oil and gas properties indicated on December 31, 2012 that its carrying amounts are expected to be recovered, but continues to be at risk for impairment if estimates of future cash flows decline. For example, the Company estimates that the carrying value of the Raton field may become partially impaired if the average gas price in Management's Price Outlooks, of $4.92 per MCF as of December 31, 2012, were to decline by approximately $0.60 to $0.80 per MCF. The Company's Raton field is a relatively long-lived asset that had a carrying value of $2.2 billion as of December 31, 2012. If the Raton field were to become impaired in a future period, the Company would recognize noncash, pretax impairment charges in that period that could range from $1.3 billion to $1.7 billion.

It is reasonably possible that the estimate of undiscounted future net cash flows attributable to these or other properties may change in the future resulting in the need to impair their carrying values. The primary factors that may affect estimates of future cash flows are (i) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves (ii) results of future drilling activities, (iii) Management's Price Outlooks and (iv) increases or decreases in production and capital costs associated with these fields.

See Notes B and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's impairment assessments.

Table of Contents

Exploration and abandonments expense. The following table provides the Company's geological and geophysical costs, exploratory dry holes expense and leasehold abandonments and other exploration expense from continuing operations for 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Geological and geophysical	$80,456	$73,552	$58,016
Exploratory dry holes	30,637	3,112	91,922
Leasehold abandonments and other	95,198	44,656	39,659
	$206,291	$121,320	$189,597

During 2012, the Company's exploration and abandonment expense was primarily attributable to $80.5 million of geological and geophysical costs, of which $52.4 million was geological and geophysical administrative costs; $30.6 million were dry hole provisions, $21.6 million was associated with the Company's unsuccessful Sikumi #1 well that was drilled to test the Ivishak zone on the west side of the Company's Oooguruk unit in Alaska; and $94.7 million was leasehold abandonment expense, which included $72.5 million associated with the Company's unproved properties in the Barnett Shale and other unproved property abandonments. The other significant components of the Company's 2012 leasehold abandonment expense included $9.5 million in the Eagle Ford Shale area, $4.8 million in the Rockies area and $4.7 million in the Permian Basin. During 2012, the Company completed and evaluated 229 exploration/extension wells, 223 of which were successfully completed as discoveries.

During 2011, the Company's exploration and abandonment expense was primarily attributable to $73.6 million of geological and geophysical costs, of which amount $42.5 million was geological and geophysical administrative costs, and $44.2 million of leasehold abandonment expense. The significant components of the Company's 2011 leasehold abandonment expense included dry gas unproved acreage abandonments of $14.5 million in the Barnett Shale area, $9.3 million in the South Texas area and $9.1 million in the Rockies area. During 2011, the Company completed and evaluated 168 exploration/extension wells, 167 of which were successfully completed as discoveries.

During 2010, the Company's exploration and abandonment expense was primarily attributable to $58.0 million of geological and geophysical costs, of which amount $39.9 million was geological and geophysical administrative costs, $96.7 million of dry hole and leasehold abandonment expense resulting from the Company's decision not to pursue development of the Cosmopolitan Unit in the Cook Inlet of Alaska and other dry hole provisions and unproved property abandonments. Other significant components of the Company's 2010 unproved abandonments included $6.3 million in the Raton Basin area, $6.0 million in the Permian Basin area and $4.9 million in the Barnett Shale area. During 2010, the Company completed and evaluated 37 exploration/extension wells, 34 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense from continuing operations totaled $248.3 million, $193.2 million and $164.3 million during 2012, 2011 and 2010, respectively. The increase in 2012, as compared to 2011, is primarily due to increases of $46.6 million and $4.7 million in compensation and occupancy expenses, respectively, related to staffing increases in support of the Company's capital expansion and integrated services initiatives.

The increase in general and administrative expense during 2011, as compared to 2010, was primarily due to increases of $31.9 million and $5.7 million in compensation and occupancy expenses, respectively, related to staffing increases in support of the Company's capital expansion and integrated services initiatives, partially offset by an increase in producing, drilling and other overhead recoveries.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations from continuing operations was $9.9 million, $8.3 million and $7.9 million during 2012, 2011 and 2010, respectively. The 19 percent and five percent increases in accretion of discount on asset retirement obligations during 2012 and 2011, respectively, are primarily due to additional well completions resulting from the Company's drilling activities. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary

Data" for additional information regarding the Company's asset retirement obligations.
Interest expense. Interest expense was $204.2 million, $181.7 million and $183.1 million during 2012, 2011 and 2010, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2012 was 6.0 percent, as compared to 7.2 percent and 7.1 percent for the years ended December 31, 2011 and 2010, respectively.
The $22.5 million increase in interest expense during 2012, as compared to 2011, is primarily due to an $868.9 million increase in the Company's average outstanding indebtedness, partially offset the 1.2 percent decline in weighted average interest on indebtedness.

See Notes G and Q of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's long-term debt and interest expense.
Other expenses. Other expenses from continuing operations were $113.4 million during 2012, as compared to $63.2 million during 2011 and $78.4 million during 2010. The $50.2 million increase in other expense during 2012, as compared to 2011, is primarily due to $15.8 million of contract rig termination fees incurred during 2012, a $13.9 million increase in unused gas transportation commitment charges and a $13.1 million increase in the time that drilling rigs and fracture stimulation equipment were not being utilized.
The $15.2 million decrease in other expense during 2011, as compared to 2010, is primarily due to a $30.4 million decrease in charges recorded associated with contracted rig rates that exceeded market rig rates that were able to be charged to joint operations and idle drilling rig and fracture stimulation equipment charges and a $7.6 million decrease in inventory impairments; partially offset by a $21.7 million increase in charges associated with excess gas transportation capacity.
See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's other expenses.
Income tax provision. The Company recognized income tax provisions attributable to earnings from continuing operations of $92.4 million, $197.6 million and $269.6 million during 2012, 2011 and 2010, respectively. The Company's effective tax rates on earnings from continuing operations, excluding income from noncontrolling interest, for 2012, 2011 and 2010 were 40 percent, 32 percent and 36 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 37 percent. The increase in the Company's 2012 effective tax rate is primarily due to changes in permanent tax differences and state apportionment factors.
See "Critical Accounting Estimates" below and Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's income tax rates and attributes.
Income (loss) from discontinued operations, net of tax. During December 2011, the Company committed to a plan to exit South Africa and initiated a process to divest Pioneer South Africa. The assets and liabilities of Pioneer South Africa are classified as discontinued operations held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2011. 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 $60.0 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 net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a pretax gain of $28.6 million. Pioneer South Africa's historical results of operations, and the related gain recorded on the disposition of Pioneer South Africa, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.
During December 2010, the Company committed to a plan to sell Pioneer Tunisia and in February 2011 sold 100 percent of the Company's share holdings in Pioneer Tunisia for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a pretax gain of $645.2 million. Accordingly, the Company classified the results of operations of Pioneer Tunisia as income from discontinued operations, net of tax in the accompanying consolidated statements of operations for the years ended December 31, 2011 and 2010.
The Company recognized income from discontinued operations, net of tax of $55.1 million for 2012 as compared to income of $423.2 million for 2011 and $134.1 million for 2010. The $368.0 million decrease in income from discontinued operations during 2012, as compared to 2011 is primarily attributable to the after tax gain on the sale of Pioneer Tunisia recorded in 2011, partially offset by the after tax gain on the sale of Pioneer South Africa during 2012.
The $289.1 million increase in income from discontinued operations during 2011, as compared to 2010 is primarily attributable to the after tax gain on the sale of Pioneer Tunisia during 2011, partially offset by Pioneer South Africa and Pioneer Tunisia operating income classified as discontinued operations during 2010. 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 discontinued operations.

Net income attributable to noncontrolling interest. Net income attributable to noncontrolling interests was $50.5 million, $47.4 million and $40.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. The Company's net income attributable to noncontrolling interest is primarily associated with the net income of Pioneer Southwest that is allocated to limited partners. The $3.1 million increase in net income attributable to noncontrolling interest in 2012, as compared to 2011, is primarily due to a 10 percent increase in noncontrolling interest in Pioneer Southwest during November 2011 as a result of an offering by

Pioneer Southwest of 4.4 million common units, representing limited partnership units, of which 1.8 million common units were sold by the Company. Partially offsetting the increase in noncontrolling interest in Pioneer Southwest was a $15.3 million decline in Pioneer Southwest's net income during 2012, as compared to 2011.

The $6.6 million increase in net income attributable to noncontrolling interest in 2011, as compared to 2010, is primarily due to an increase in Pioneer Southwest's sales volumes and realized oil prices. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding Pioneer Southwest and the Company's noncontrolling interest in consolidated subsidiaries' net income.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for capital expenditures and acquisition expenditures on oil and gas properties and related vertical integration assets and facilities, payments of contractual obligations, dividends/distributions and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, cash and cash equivalents on hand, proceeds from the sale of joint interests and nonstrategic assets or external financing sources as discussed in "Capital resources" below. During 2013, the Company expects that it will be able to fund its needs for cash (excluding acquisitions) with a combination of internally generated cash flows, cash and cash equivalents on hand, proceeds from the sale of joint interests, availability under its credit facility and issuances of debt or equity securities. Although the Company expects that these sources of funding will be adequate to fund capital expenditures and dividend/distribution payments and provide adequate liquidity to fund other needs, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

During 2013, the Company plans to continue to focus its capital spending primarily on liquids-rich drilling activities. The Company's 2013 capital budget totals $3.0 billion (excluding effects of acquisitions, asset retirement obligations, capitalized interest, geological and geophysical administrative costs and EFS Midstream capital contributions), consisting of $2.75 billion for drilling operations and $240 million for buildings, expansion of the Company's principal sand mine in Brady, Texas and vertical integration additions. Based on the Company's current Management Price Outlooks, Pioneer expects its net cash flows from operating activities, cash and cash equivalents on hand, proceeds from assets sales and/or joint ventures, availability under the Credit Facility and issuances of debt or equity securities to be sufficient to fund its planned capital expenditures and contractual obligations.

Investing activities. Net cash used in investing activities during 2012 was $3.3 billion, as compared to net cash used in investing activities of $1.6 billion and $954.9 million during 2011 and 2010, respectively. The increase in net cash flow used in investing activities during 2012, as compared to 2011, is primarily due to (i) an $831.1 million increase in additions to oil and gas properties associated with the Company's capital programs, (ii) a $723.5 million decrease in proceeds from disposition of assets (primarily attributable to the 2011 sale of Pioneer Tunisia, partially offset by proceeds from the sales of Pioneer South Africa and a partial interest in certain Eagle Ford Shale unproved leaseholds during 2012) and (iii) the $297.1 million acquisition of Premier Silica, partially offset by (iv) an $89.6 million decrease in investments in EFS Midstream and (v) a $66.4 million decrease in additions to other assets and other property and equipment. During the year ended December 31, 2012, the Company's investing activities were funded by net cash provided by operating activities, cash on hand and borrowings under long-term debt.

The increase in net cash flow used in investing activities during 2011, as compared to 2010, was comprised of a $915.5 million increase in additions to oil and gas properties, an increase of $178.9 million in additions to other assets and other property and equipment and a $16.8 million increase in investments in unconsolidated subsidiaries, partially offset by an increase of $505.3 million in proceeds from disposition of assets (primarily related to the sale of Pioneer Tunisia during February 2011). See "Results of Operations" above and Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Dividends/distributions. During each of the years ended December 31, 2012, 2011 and 2010, the Board declared semiannual dividends of $0.04 per common share. Associated therewith, the Company paid $10.0 million, $9.6

million and $9.5 million, respectively, of aggregate dividends. Future dividends are at the discretion of the Board, and, if declared, the Board may change the dividend amount based on the Company's liquidity and capital resources at the time.

During January, April, July and October of 2012, 2011 and 2010, the board of directors of the general partner of Pioneer Southwest (the "Pioneer Southwest Board") declared quarterly distributions aggregating annually to $2.07, $2.03 and $2.00 per limited partner unit, respectively. Associated therewith, Pioneer Southwest paid aggregate distributions to noncontrolling unitholders of $35.2 million, $25.6 million and $25.2 million during the years ended December 31, 2012, 2011 and 2010, respectively. Future distributions of Pioneer Southwest are at the discretion of the Pioneer Southwest Board, and, if declared, the Pioneer Southwest Board may change the distribution amount based on Pioneer Southwest's liquidity and capital resources at the time.

Off-balance sheet arrangements. From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2012, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling and firm transportation commitments, (iv) open purchase commitments and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates and gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput. Other than the off-balance sheet arrangements described above and subsequent events that are described in "Financial and Operating Performance," above and in Note Q of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data," the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "Contractual obligations" below for more information regarding the Company's off-balance sheet arrangements.

Contractual obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments (including commitments to pay day rates for drilling rigs), capital funding obligations, derivative obligations, other liabilities (including postretirement benefit obligations), firm transportation and fractionation commitments and minimum annual gathering, treating and transportation commitments. Other joint owners in the properties operated by the Company will incur portions of the costs represented by these commitments.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2012:

	Payments Due by Year			
	2013	2014 and 2015	2016 and 2017	Thereafter
	(in thousands)			
Long-term debt (a)	$479,907	$—	$1,540,485	$1,749,500
Operating leases (b)	24,096	32,934	28,455	36,967
Drilling commitments (c)	174,169	131,641	585	—
Derivative obligations (d)	13,416	12,307	—	—
Open purchase commitments (e)	131,727	—	—	—
Other liabilities (f)	31,056	31,580	30,265	189,024
Firm gathering, processing and transportation commitments (g)	264,213	760,341	725,378	1,255,520
	$1,118,584	$968,803	$2,325,168	$3,231,011

(a) Long-term debt includes $479.9 million principal amount of the Convertible Senior Notes. The Company currently anticipates that it will redeem all Convertible Senior Notes that remain outstanding during 2013. See Notes G and Q of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for further information on the conversion of these Convertible Senior Notes. Also, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for information regarding estimated future interest payment obligations under long-term debt obligations. The amounts included in the table above represent principal maturities only.

(b) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's operating leases.

(c) Drilling commitments represent future minimum expenditure commitments for drilling rig services and well commitments under contracts to which the Company was a party on December 31, 2012.

(d) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity and interest rate derivatives that were valued as of December 31, 2012. The ultimate settlement amounts of the Company's derivative obligations are unknown because they 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 additional information regarding the Company's derivative obligations.

(e) Open purchase commitments primarily represent expenditure commitments for inventory, materials and other property, plant and equipment ordered, but not received, as of December 31, 2012.

(f) The Company's other liabilities represent current and noncurrent other liabilities that are comprised of postretirement benefit obligations, litigation and environmental contingencies, asset retirement obligations and other obligations for which neither the ultimate settlement amounts nor their timings can be precisely determined in advance. See Notes H, I and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's postretirement benefit obligations, asset retirement obligations and litigation and environmental contingencies, respectively.

(g) Gathering, processing and transportation commitments represent estimated fees on production throughput commitments. See "Item 2. Properties" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's gathering, processing and transportation commitments.

Capital resources. The Company's primary capital resources are cash and cash equivalents, net cash provided by operating activities, proceeds from sales of joint interests and nonstrategic assets and proceeds from financing activities (principally borrowings under the Credit Facility or issuances of debt or equity securities). If internal cash flows and cash on hand do not meet the Company's expectations, the Company may reduce its level of capital expenditures, and/or fund a portion of its capital expenditures using availability under the Credit Facility, issue debt or equity securities or obtain capital from other sources, such as through sales of joint interests or nonstrategic assets.

Operating activities. Net cash provided by operating activities for the years ended December 31, 2012, 2011 and 2010 was $1.8 billion, $1.5 billion and $1.3 billion, respectively. The increases in net cash flow provided by operating activities in both 2012 and 2011 were primarily due to increases in oil and gas sales and realized derivative gains in each year.

Asset divestitures. 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 $1.7 billion. At closing, Sinochem will pay $522.0 million in cash to Pioneer, before normal closing adjustments, and will pay the remaining $1.2 billion by carrying 75 percent of Pioneer's portion of future drilling and facilities costs attributable to the horizontal Wolfcamp Shale play. This transaction is expected to close during the second quarter of 2013, subject to governmental and third party approvals.

During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party for $60.0 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 net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a pretax gain of $28.6 million. During 2011, the Company completed the sale of Pioneer Tunisia to an unaffiliated party for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a pretax gain of $645.2 million.

In June 2010, the Company entered into an Eagle Ford Shale joint venture. Associated therewith, the Company sold 45 percent of its Eagle Ford Shale proved and unproved oil and gas properties to an unaffiliated third party for $212.0 million of cash proceeds. Under the terms of the transaction, the purchaser also paid 75 percent (representing $886.8 million) of the Company's defined exploration, drilling and completion costs attributable to the Eagle Ford Shale assets during the period from June 2010 through December 2012.

During the first half of 2010, the Company sold certain proved and unproved oil and gas properties in the Uinta/Piceance area for net proceeds of $11.8 million and the assumption by the purchaser of certain asset retirement obligations, resulting in a pretax gain of $17.3 million.

See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding the Company's divestitures.

Financing activities. Net cash provided by financing activities during 2012 was $1.1 billion, as compared to net cash provided by financing activities during 2011 of $457.4 million and net cash used in 2010 of $246.4 million. During 2012, the significant components of financing activities included $1.2 billion of net borrowings on long-term debt and $45.9 million of payments associated with dividends and distributions to noncontrolling interests. During 2011, significant components of financing activities included $484.2 million of net proceeds received from the offering of 5.5 million shares of the Company's common stock, $123.0 million of net proceeds received from the sale of 4.4 million common units representing limited partner interests in Pioneer Southwest, partially offset by $98.3 million of net principal payments on long-term debt and $36.3 million of payments associated with dividends and distributions to noncontrolling interests. During 2010, significant components of financing activities included $182.9 million of net principal payments on long-term debt and $36.3 million of payments associated with dividends and distributions to noncontrolling interests.

The following provides a description of the Company's significant financing activities during 2012, 2011 and 2010:

- During December 2012, the Company amended its Credit Facility with a syndicate of financial institutions to increase the aggregate loan commitments to $1.5 billion from $1.25 billion and extend its maturity to December 2017;

Table of Contents

- During June 2012, the Company issued $600 million of 3.95% Senior Notes due 2022 and received proceeds, net of $8.5 million of offering discounts and costs, of $591.5 million;
- During December 2011, Pioneer Southwest completed the public offering of 4.4 million common units of Pioneer Southwest, representing limited partnership interests, at a per-unit price of $29.20, before offering costs. Of the 4.4 million common units, Pioneer sold 1.8 million of its Pioneer Southwest common unit holdings for net proceeds of $50.5 million and Pioneer Southwest issued 2.6 million new common units for net proceeds of $72.5 million, including offering costs. Pioneer Southwest used its net proceeds to reduce its credit facility borrowings; and
- During November 2011, the Company completed the sale of 5.5 million shares of its common stock for $484.2 million of net proceeds.

During December 2012, the Company's stock price performance met the average price threshold that causes the Convertible Senior Notes to become convertible at the option of the holders for the three months ending March 31, 2013. Associated therewith, in January and February 2013, holders of $240.6 million principal amount of the Convertible Senior Notes exercised their right to convert their Convertible Senior Notes into cash and shares of common stock. In general, upon conversion of a Convertible Senior Note, the holder will receive cash equal to the principal amount of the Convertible Senior Note and common stock for the Convertible Senior Note's conversion value in excess of the principal amount. The Company anticipates redeeming all Notes that remain outstanding during 2013; however, the decision to exercise the redemption option will depend on market and other conditions, and the Company may choose not to redeem the Notes during 2013 or at all. If the Company exercises its redemption option, the Convertible Senior Notes will automatically become convertible during the period between when the Company gives notice of its intent to redeem the Convertible Senior Notes and the date on which the Convertible Senior Notes are actually redeemed. If the Company exercises its redemption option and the Company's stock price averages above $72.60 per share during the conversion period, the Company expects that the note holders will exercise their right to convert the Convertible Senior Notes, receiving cash and shares of common stock, rather than allow their securities to be redeemed by the Company for cash. If all the outstanding Convertible Senior Notes had been converted on December 31, 2012, the holders would have received $479.9 million of cash and approximately 3.4 million shares of the Company's common stock, which were valued at $358.8 million based on the closing price of the common stock on December 31, 2012.

Interest on the principal amount of the Convertible Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. Beginning on January 15, 2013, during any six-month period thereafter from January 15 to July 14 and from July 15 to January 14, if the average trading price (as defined in the Convertible Senior Notes indenture supplement) of a Convertible Senior Note for the five consecutive trading days immediately preceding the first day of the applicable six-month interest period equals or exceeds 120 percent of the principal amount of the note, interest on the principal amount of the Convertible Senior Notes will be 2.375 percent solely for the relevant interest period. The trading price of the Convertible Senior Notes for the five consecutive trading days preceding January 15, 2013 exceeded 120 percent of the principal amount of the note and, accordingly, the interest rate in effect during the January 15, 2013 to July 15, 2013 period has been reduced to 2.375 percent.

See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the significant financing activities.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company cannot predict the timing or ultimate outcome of any such actions as they are subject to market conditions, among other factors. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal sources of short-term liquidity are cash and cash equivalents and unused borrowing capacity under the Credit Facility. As of December 31, 2012, the Company had outstanding borrowings of $474.0 million under the Credit Facility, leaving $1.0 billion of unused borrowing capacity. The Company was in compliance with all of its debt covenants. The Credit Facility contains certain financial covenants, which include the maintenance of a ratio of total debt to book capitalization less intangible assets, accumulated other comprehensive income and certain noncash asset impairments not to exceed .60 to 1.0, which is above the Company's December 31, 2012 ratio of .39 to 1.0. If internal cash flows and cash on hand do not meet the Company's expectations, the Company may reduce its level of capital expenditures, reduce dividend payments, and/or fund a portion of its capital expenditures using borrowings under the Credit Facility, issuances of debt or equity securities or other sources, such as sales of joint interests or nonstrategic assets. The Company cannot provide any assurance that needed short-term or long-term liquidity will be available on acceptable terms or at all. Although the Company expects that the combination of internal operating cash flows, cash and cash equivalents on hand, proceeds from the sales of joint interests or nonstrategic assets, available capacity under the Credit Facility and issuance of debt or equity securities will be adequate to fund 2013 capital expenditures and dividend/distribution payments and provide adequate liquidity to fund other needs, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

Debt ratings. The Company receives debt credit ratings from several of the major ratings agencies, which are subject to regular reviews. The Company believes that each of the rating agencies considers many factors in determining the Company's ratings, including production growth opportunities, liquidity, debt levels and asset composition and proved reserve mix. A reduction in the Company's debt ratings could negatively affect the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. In 2011, the Company achieved an investment grade rating with one of the credit rating agencies and, in 2012, the Company achieved an investment grade rating with a second credit rating agency.

Book capitalization and current ratio. The Company's net book capitalization at December 31, 2012 was $9.4 billion, consisting of $229.4 million of cash and cash equivalents, debt of $3.7 billion and stockholders' equity of $5.9 billion. The Company's debt to book capitalization increased to 37 percent at December 31, 2012 from 26 percent at December 31, 2011, primarily due to an increase in indebtedness during 2012. The Company's ratio of current assets to current liabilities was 1.02 to 1.00 at December 31, 2012, as compared to 1.31 to 1.00 at December 31, 2011.

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with GAAP. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a comprehensive discussion of the Company's significant accounting policies. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of the Company's most critical accounting estimates, judgments and uncertainties that are inherent in the Company's application of GAAP.

Asset retirement obligations. The Company has significant obligations to remove tangible equipment and facilities and to restore the land at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is generally made to the oil and gas property balance. See Notes B and I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method, particularly during periods of active exploration. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During 2012, 2011 and 2010, the Company recognized exploration, abandonment, geological and geophysical expense from continuing operations of $206.3 million, $121.3 million and $189.6 million, respectively. During 2012, 2011 and 2010, the Company recognized exploration, abandonment, geological and geophysical expense from discontinued operations of $70 thousand, $4.3 million and $15.9 million, respectively, under the successful efforts method.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

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

The Company's proved reserve information included in this Report as of December 31, 2012, 2011 and 2010 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2012 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2012 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 1A. Risk Factors" and "Item 2. Properties" for additional information regarding estimates of proved reserves.

The Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of the Company's assessment of its proved properties and goodwill for impairment.

Impairment of proved oil and gas properties. The Company reviews its proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon estimated future recoverable proved and risk-adjusted probable and possible reserves, Management's Price Outlooks, production and capital costs expected to be incurred to recover the reserves; discount rates commensurate with the nature of the properties and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated. See Notes B and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's impairment assessments.

Impairment of unproved oil and gas properties. At December 31, 2012, the Company carried unproved property costs of $231.6 million. Management assesses unproved oil and gas properties for impairment on a project-by-project basis. Management's impairment assessments include evaluating the results of exploration activities, Management's Price Outlooks and planned future sales or expiration of all or a portion of such projects.

Suspended wells. The Company suspends the costs of exploratory wells that discover hydrocarbons pending a final determination of the commercial potential of the discovery. The ultimate disposition of these well costs is dependent on the results of future drilling activity and development decisions. If the Company decides not to pursue additional appraisal activities or development of these fields, the costs of these wells will be charged to exploration and abandonment expense.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well.

(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves to sanction the project or is noncommercial and is impaired. See Note F of Notes to Consolidated Financial Statements included in "Item 8.

Financial Statements and Supplementary Data" for additional information regarding the Company's suspended exploratory well costs.

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets, if any, will be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurance that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. During the third quarter of 2012, the Company performed a qualitative assessment of goodwill in accordance with Financial Accounting Standards Board Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350) which permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Company determined that it was not likely that the Company's goodwill was impaired.

For assessments prior to 2012, the Company was required to estimate the fair value of the assets and liabilities of the reporting units that have goodwill. There is considerable judgment involved in estimating fair values, particularly in determining the valuation methodologies to utilize, the estimation of proved reserves as described above and the weighting of different valuation methodologies applied. The carrying value of the Company's goodwill was assessed and found not to be impaired during the years ended December 31, 2011 and 2010. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding goodwill and assessments of goodwill for impairment.

Litigation and environmental contingencies. The Company makes judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. Under GAAP, a liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commitments and contingencies.

Valuation of stock-based compensation. In accordance with GAAP, the Company calculates the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. The Company utilizes (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the closing stock price on the day prior to the date of grant for the fair value of restricted stock awards, (c) the closing stock price at the balance sheet date for restricted stock awards that are expected to be settled wholly or partially in cash on their vesting date, (d) the Monte Carlo simulation method for the fair value of performance unit awards, and (e) a probability forecasted fair value method for Series B unit awards issued by Sendero Drilling Company, LLC. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's stock-based compensation.

Valuation of other assets and liabilities at fair value. In accordance with GAAP, the Company periodically measures and records certain assets and liabilities at fair value. The assets and liabilities that the Company periodically measures and records at fair value include trading securities, commodity derivative contracts and interest rate contracts. The Company also measures and discloses certain financial assets and liabilities at fair value, such as long-term debt. The valuation methods used by the Company to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as future prices, credit-adjusted risk-free rates and current volatility factors. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the methods used by management to estimate the fair values of these assets and liabilities.

New Accounting Pronouncements

There are no new accounting pronouncements that are likely of having a material impact on the Company's consolidated financial statements.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2012, and from which the Company may incur future gains or losses from changes in commodity prices or interest rates.

The fair values of the Company's derivative contracts are determined based on the Company's valuation models and applications. As of December 31, 2012, the Company was a party to commodity swap contracts, interest rate swap contracts, commodity collar contracts and commodity collar contracts with short put options. See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2012:

	Derivative Contract Net Assets (Liabilities)		
	Commodities	Interest Rate	Total
	(in thousands)		
Fair value of contracts outstanding as of December 31, 2011	$ 389,753	$ (15,654)	$ 374,099
Changes in contract fair values (a)	352,679	(22,428)	330,251
Contract maturities	(277,462)	—	(277,462)
Contract terminations	(146,593)	28,358	(118,235)
Fair value of contracts outstanding as of December 31, 2012	$ 318,377	$ (9,724)	$ 308,653

(a) At inception, new derivative contracts entered into by the Company generally have no intrinsic value.

Quantitative Disclosures

Interest rate sensitivity. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and Capital Commitments, Capital Resources and Liquidity included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding debt transactions.

The following tables provide information about financial instruments to which the Company was a party as of December 31, 2012 that were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rates represent the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2012. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 8, 2013.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

INTEREST RATE SENSITIVITY
DEBT OBLIGATIONS AND DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2012

	Year Ending December 31,							Liability Fair Value at December 31,
	2013	2014	2015	2016	2017	Thereafter	Total	2012
Total Debt:	(in thousands, except percentages)							
Fixed rate principal maturities (a)	$479,907	$—	$—	$455,385	$485,100	$1,749,500	$3,169,892	$(3,939,650)
Weighted average interest rate	6.12 %	6.15 %	6.15 %	6.17 %	6.11 %	6.28 %		
Variable rate principal maturities:								
Pioneer Natural Resources credit facility	$—	$—	$—	$—	$474,000	$—	$474,000	$(492,485)
Weighted average interest rate	1.83 %	2.01 %	2.35 %	2.70 %	2.95 %	— %		
Pioneer Southwest credit facility	$—	$—	$—	$—	$126,000	$—	$126,000	$(123,635)
Weighted average interest rate	1.96 %	2.13 %	2.48 %	2.83 %	3.07 %	— %		
Interest Rate Swaps:								
Notional debt amount	$—	$—	$—	$250,000	$—	$—	$250,000	$(9,724)
Fixed rate payable (%)	— %	— %	— %	3.21 %	— %	— %		
Variable rate receivable (%)	— %	— %	— %	3.01 %	— %	— %		

(a) Represents maturities of principal amounts excluding debt issuance discounts and net deferred fair value hedge losses.

Commodity derivative instruments and price sensitivity. The following tables provide information about the Company's oil, NGL, diesel and gas derivative financial instruments that were sensitive to changes in commodity prices as of December 31, 2012. Declines in commodity prices would reduce the Company's revenues, although the liquidity effects of such fluctuations would be mitigated by the Company's derivative activities.

The Company manages commodity price risk with derivative swap contracts, collar contracts and collar contracts with short put options. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor" or "long put") and maximum ("ceiling") prices on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price. Collar contracts with short put options differ from other collar contracts by virtue of the short put option price, below which the Company's realized price will exceed the variable market prices by the floor-to-short put price differential.

See Notes B, D and E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the accounting procedures followed by the Company relative to its derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil, NGL or gas prices.

OIL PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2012

	Year Ending December 31,			Asset (Liability) Fair Value at December 31,
	2013	2014	2015	2012 (in thousands)
Oil Derivatives:				
Average daily notional BBL volumes:				
Swap contracts	3,000	—	—	$ (13,225)
Weighted average fixed price per BBL	$81.02	$—	$—	
Collar contracts with short puts (a)	71,029	60,000	26,000	$ 160,817
Weighted average ceiling price per BBL	$119.76	$117.06	$104.45	
Weighted average floor price per BBL	$92.27	$92.67	$95.00	
Weighted average short put price per BBL	$74.28	$76.58	$80.00	
Average forward NYMEX oil prices (b)	$97.24	$95.03	$91.18	
Rollfactor swap contracts (a)	6,000	—	—	$ 1,375
Weighted average fixed price per BBL (c)	$0.43	$—	$—	
Average forward NYMEX rollfactor prices (b)	$(0.14)	$—	$—	
Basis swap contracts (d)	2,055	—	—	$ 301
Weighted average fixed price per BBL	$(5.75)	$—	$—	
Average forward basis differential prices (e)	$(1.25)	$—	$—	

(a) During the period from January 1, 2013 to February 8, 2013, the Company entered into additional 2014 (i) collar contracts with short puts for 9,000 BBLs per day with a ceiling price of $104.13 per BBL, a floor price of $95.00 per BBL and a short put price of $80.00 per BBL and (ii) rollfactor swap contracts for 15,000 BBLs per day priced at $0.38 per BBL; and (iii) replaced 5,000 BBLs per day of 2014 collar contracts with short puts with a ceiling price of $124.00 per BBL, a floor price of $90.00 per BBL and short put price of $72.00 per BBL with 5,000 BBLs per day of 2014 collar contracts with short puts with a ceiling price of $105.74 per BBL, a floor price of $100.00 per BBL and short put price of $80.00 per BBL.

(b) The average forward NYMEX oil prices are based on February 8, 2013 market quotes.

(c) Represents swaps that fix the difference between (i) each day's price per BBL of WTI for the first nearby month less (ii) the price per BBL of WTI for the second nearby NYMEX month, multiplied by .6667; plus (iii) each day's price per BBL of WTI for the first nearby month less (iv) the price per BBL of WTI for the third nearby NYMEX month, multiplied by .3333.

(d) During the period from January 1, 2013 to February 8, 2013, the Company entered into additional basis swap contracts for 1,000 BBLs per day of October through December 2013 production with a price differential between Cushing WTI and Louisiana Light Sweet crude of $7.60 per BBL.

(e) The average forward basis differential prices are based on February 8, 2013 market quotes for basis differentials between Midland WTI and Cushing WTI.

Table of Contents

NGL PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2012

	Year Ending December 31,		Asset Fair Value at December 31, 2012
	2013	2014	(in thousands)
NGL Derivatives:			
Average daily notional BBL volumes:			
Collar contracts with short puts	1,064	1,000	$1,799
Weighted average ceiling price per BBL	$105.28	$109.50	
Weighted average floor price per BBL	$89.30	$95.00	
Weighted average short put price per BBL	$75.20	$80.00	
Average forward NGL prices (a)	$91.88	$84.91	

(a) Forward component NGL prices are derived from active-market NGL component price quotes as of February 8, 2013.

GAS PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2012

	Year Ending December 31,			Asset (Liability) Fair Value at December 31, 2012
	2013	2014	2015	(in thousands)
Gas Derivatives:				
Average daily notional MMBTU volumes:				
Swap contracts	162,500	105,000	—	$ 93,581
Weighted average fixed price per MMBTU	$5.13	$4.03	$—	
Collar contracts	150,000	—	—	$ 81,332
Weighted average ceiling price per MMBTU	$6.25	$—	$—	
Weighted average floor price per MMBTU	$5.00	$—	$—	
Collar contracts with short puts	—	25,000	225,000	$ (1,954)
Weighted average ceiling price per MMBTU	$—	$4.70	$5.09	
Weighted average floor price per MMBTU	$—	$4.00	$4.00	
Weighted average short put price per MMBTU	$—	$3.00	$3.00	
Average forward NYMEX gas prices (a)	$3.58	$4.04	$4.25	
Basis swap contracts	162,500	10,000	—	$ (5,627)
Weighted average fixed price per MMBTU	$(0.22)	$(0.19)	$—	
Average forward basis differential prices (b)	$(0.11)	$(0.20)	$—	

(a) The average forward NYMEX gas prices are based on February 8, 2013 market quotes.
(b) The average forward basis differential prices are based on February 8, 2013 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

Marketing derivative instruments and price sensitivity. The Company manages commodity price risk and mitigates firm transportation commitment costs with derivative contracts. Periodically, the Company enters into gas buy and sell marketing arrangements to fulfill firm pipeline transportation commitments. Associated with these marketing arrangements, the Company may enter into gas index swaps to mitigate price risk.

MARKETING GAS PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2012

	Quarter Ending March 31, 2013	Liability Fair Value at December 31, 2012 (in thousands)
Average Daily Gas Production Associated with Marketing Derivatives (MMBTU):		
Basis swap contracts:		
Index swap volume (a)	40,000	$(22)
Price differential ($/MMBTU)	$0.25	
Average forward basis differential prices (b)	$0.26	

(a) During the period from January 1, 2013 to February 8, 2013, the Company entered into additional marketing derivative gas index swap contracts for 25,000 MMBTU per day for April 2013 volumes with a price differential of $0.35 per MMBTU.

(b) The average forward basis differential prices are based on February 8, 2013 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

Qualitative Disclosures

The Company's primary market risk exposures are to changes in commodity prices and interest rates. These risks did not change materially from December 31, 2011 to December 31, 2012.

Non-derivative financial instruments. The Company is a borrower under fixed rate and variable rate debt instruments that give rise to interest rate risk. The Company's objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing the Company's costs of capital. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's debt instruments.

Derivative financial instruments. The Company, from time to time, utilizes commodity price and interest rate derivative contracts to mitigate commodity price and interest rate risks in accordance with policies and guidelines approved by the Board. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of derivative transactions.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC
ACCOUNTING FIRM

The Board of Directors and Stockholders of
Pioneer Natural Resources Company

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pioneer Natural Resources Company at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pioneer Natural Resources Company's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 13, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Dallas, Texas
February 13, 2013

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$229,396	$537,484
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $848 and $806 as of December 31, 2012 and December 31, 2011, respectively	316,854	275,991
Due from affiliates	3,299	7,822
Income taxes receivable	7,447	3
Inventories	197,056	241,609
Prepaid expenses	13,438	14,263
Discontinued operations held for sale	—	73,349
Other current assets:		
Derivatives	279,119	238,835
Other	3,746	12,936
Total current assets	1,050,355	1,402,292
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	14,259,708	12,013,805
Unproved properties	231,555	235,527
Accumulated depletion, depreciation and amortization	(4,412,913)	(3,648,465)
Total property, plant and equipment	10,078,350	8,600,867
Goodwill	298,142	298,142
Other property and equipment, net	1,217,694	573,075
Other assets:		
Investment in unconsolidated affiliate	204,129	169,532
Derivatives	55,257	243,240
Other, net of allowance for doubtful accounts of $629 and $340 as of December 31, 2012 and December 31, 2011, respectively	165,103	160,008
	$13,069,030	$11,447,156

The accompanying notes are an integral part of these consolidated financial statements.

71

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)
(in thousands, except share data)

	December 31, 2012	2011
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$729,942	$647,455
Due to affiliates	96,935	68,756
Interest payable	68,083	57,240
Income taxes payable	208	9,788
Deferred income taxes	86,481	57,713
Discontinued operations held for sale	—	75,901
Other current liabilities:		
Derivatives	13,416	74,415
Deferred revenue	—	42,069
Other	39,725	36,174
Total current liabilities	1,034,790	1,069,511
Long-term debt	3,721,193	2,528,905
Derivatives	12,307	33,561
Deferred income taxes	2,140,416	1,942,446
Other liabilities	293,016	221,595
Equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 134,966,740 and 133,121,092 shares issued at December 31, 2012 and 2011, respectively	1,350	1,331
Additional paid-in capital	3,683,934	3,613,808
Treasury stock, at cost: 11,611,093 and 11,264,936 shares at December 31, 2012 and 2011, respectively	(510,570)	(458,281)
Retained earnings	2,514,640	2,335,066
Accumulated other comprehensive loss—net deferred hedge losses, net of tax	—	(3,130)
Total equity attributable to common stockholders	5,689,354	5,488,794
Noncontrolling interest in consolidating subsidiaries	177,954	162,344
Total equity	5,867,308	5,651,138
Commitments and contingencies		
	$13,069,030	$11,447,156

The accompanying notes are an integral part of these consolidated financial statements.

72

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2012	2011	2010
Revenues and other income:			
Oil and gas	$2,811,660	$2,294,063	$1,718,297
Interest and other	28,310	66,880	56,972
Derivative gains, net	330,251	392,752	448,434
Gain (loss) on disposition of assets, net	58,087	(3,644)	19,074
Hurricane activity, net	—	1,454	138,918
	3,228,308	2,751,505	2,381,695
Costs and expenses:			
Oil and gas production	635,644	447,142	364,764
Production and ad valorem taxes	187,757	147,664	112,141
Depletion, depreciation and amortization	810,191	578,268	499,856
Impairment of oil and gas properties	532,589	354,408	—
Exploration and abandonments	206,291	121,320	189,597
General and administrative	248,282	193,215	164,332
Accretion of discount on asset retirement obligations	9,887	8,256	7,945
Interest	204,222	181,660	183,084
Other	113,388	63,166	78,404
	2,948,251	2,095,099	1,600,123
Income from continuing operations before income taxes	280,057	656,406	781,572
Income tax provision	(92,384)	(197,644)	(269,627)
Income from continuing operations	187,673	458,762	511,945
Income from discontinued operations, net of tax	55,149	423,152	134,050
Net income	242,822	881,914	645,995
Net income attributable to noncontrolling interests	(50,537)	(47,425)	(40,787)
Net income attributable to common stockholders	$192,285	$834,489	$605,208
Basic earnings per share:			
Income from continuing operations attributable to common stockholders	$1.10	$3.45	$4.00
Income from discontinued operations attributable to common stockholders	0.44	3.56	1.14
Net income attributable to common stockholders	$1.54	$7.01	$5.14
Diluted earnings per share:			
Income from continuing operations attributable to common stockholders	$1.07	$3.39	$3.96
Income from discontinued operations attributable to common stockholders	0.43	3.49	1.12
Net income attributable to common stockholders	$1.50	$6.88	$5.08
Weighted average shares outstanding:			
Basic	122,966	116,904	115,062
Diluted	126,320	119,215	116,330
Amounts attributable to common stockholders:			
Income from continuing operations	$137,136	$411,337	$471,158
Income from discontinued operations, net of tax	55,149	423,152	134,050
Net income	$192,285	$834,489	$605,208

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Net income	$242,822	$881,914	$645,995
Other comprehensive activity:			
Net hedge (gains) losses included in continuing operations	4,855	(32,636)	(84,877)
Income tax (benefit) provision	(1,725)	8,407	23,648
Other comprehensive activity	3,130	(24,229)	(61,229)
Comprehensive income	245,952	857,685	584,766
Comprehensive income attributable to the noncontrolling interests	(50,537)	(33,687)	(23,206)
Comprehensive income attributable to common stockholders	$195,415	$823,998	$561,560

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF EQUITY
(in thousands, except dividends per share)

	Equity Attributable to Common Stockholders							
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
Balance as of December 31, 2009	114,375	$1,252	$2,981,450	$(415,211)	$917,688	$ 51,009	$ 106,843	$3,643,031
Dividends declared ($0.08 per share)	—	—	—	—	(9,455)	—	—	(9,455)
Exercise of long-term incentive plan stock options and employee stock purchases	266	1	2,577	7,811	(3,014)	—	—	7,375
Purchase of treasury stock	(278)	—	—	(13,835)	—	—	(204)	(14,039)
Tax related to stock-based compensation	—	—	(153)	—	—	—	—	(153)
Compensation costs:								
Vested compensation awards, net	946	9	(8)	—	—	—	—	1
Compensation costs included in net income	—	—	38,902	—	—	—	1,283	40,185
Cash contributions from noncontrolling interests	—	—	—	—	—	—	1,151	1,151
Cash distributions to noncontrolling interests	—	—	—	—	—	—	(26,837)	(26,837)
Net income	—	—	—	—	605,208	—	40,787	645,995
Other comprehensive loss:								
Deferred hedging activity, net of tax:								
Net hedge gains included in continuing operations	—	—	—	—	—	(43,648)	(17,581)	(61,229)
Balance as of December 31, 2010	115,309	$1,262	$3,022,768	$(421,235)	$1,510,427	$ 7,361	$ 105,442	$4,226,025
	5,500	55	484,105	—	—	—	—	484,160

Issuance of common stock								
Sale of Pioneer Southwest common units, net of tax	—	—	26,915	—	—	—	8,176	35,091
Issuance of Pioneer Southwest common units, net of tax	—	—	8,104	—	—	—	40,688	48,792
Dividends declared ($0.08 per share)	—	—	—	—	(9,498)	—	—	(9,498)
Exercise of long-term incentive plan stock options and employee stock purchases	76	—	951	3,097	(352)	—	—	3,696
Purchase of treasury stock	(439)	—	—	(40,157)	—	—	(198)	(40,355)
Conversion of 2.875% convertible senior notes	—	—	(20)	14	—	—	—	(6)
Tax benefits related to stock-based compensation	—	—	31,087	—	—	—	—	31,087
Disposition of subsidiary	—	—	(510)	—	—	—	—	(510)
Compensation costs:								
Vested compensation awards, net	1,410	14	(14)	—	—	—	—	—
Compensation costs included in net income	—	—	40,422	—	—	—	1,251	41,673
Cash distributions to noncontrolling interests	—	—	—	—	—	—	(26,702)	(26,702)
Net income	—	—	—	—	834,489	—	47,425	881,914
Other comprehensive loss:								
Deferred hedging activity, net of tax:								
Net hedge gains included in continuing operations	—	—	—	—	—	(10,491)	(13,738)	(24,229)
Balance as of December 31, 2011	121,856	$1,331	$3,613,808	$(458,281)	$2,335,066	$ (3,130)	$ 162,344	$5,651,138

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF EQUITY (continued)
(in thousands, except dividends per share)

	Equity Attributable to Common Stockholders							
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
Balance as of December 31, 2011	121,856	$1,331	$3,613,808	$(458,281)	$2,335,066	$ (3,130)	$ 162,344	$5,651,138
Dividends declared ($0.08 per share)	—	—	—	—	(9,989)	—	—	(9,989)
Exercise of long-term incentive plan stock options and employee stock purchases	195	—	(849)	10,842	(2,722)	—	—	7,271
Purchase of treasury stock	(542)	—	—	(63,136)	—	—	(189)	(63,325)
Conversion of 2.875% convertible senior notes	—	—	(5)	5	—	—	—	—
Tax benefits related to stock-based compensation	—	—	58,486	—	—	—	—	58,486
Deferred tax provision attributable to 2008 Pioneer Southwest initial public offering	—	—	(49,072)	—	—	—	—	(49,072)
Compensation costs:								
Vested compensation awards, net	1,847	19	(19)	—	—	—	—	—
Compensation costs included in net income	—	—	61,585	—	—	—	1,165	62,750
Cash distributions to noncontrolling interests	—	—	—	—	—	—	(35,903)	(35,903)
Net income	—	—	—	—	192,285	—	50,537	242,822
Other comprehensive income:								
Deferred hedging activity, net of tax:								
	—	—	—	—	—	3,130	—	3,130

Net hedge losses included in continuing operations								
Balance as of December 31, 2012	123,356	$1,350	$3,683,934	$(510,570)	$2,514,640	$ —	$ 177,954	$5,867,308

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents
PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$242,822	$881,914	$645,995
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	810,191	578,268	499,856
Impairment of oil and gas properties	532,589	354,408	—
Exploration expenses, including dry holes	125,376	47,231	132,772
Hurricane activity, net	—	—	4,508
Deferred income taxes	85,459	188,579	259,763
(Gain) loss on disposition of assets, net	(58,087)	3,644	(19,074)
Accretion of discount on asset retirement obligations	9,887	8,256	7,945
Discontinued operations	(19,344)	(376,717)	77,158
Interest expense	35,563	31,483	30,472
Derivative related activity	68,604	(221,899)	(419,809)
Amortization of stock-based compensation	62,567	41,442	39,854
Amortization of deferred revenue	(42,069)	(44,951)	(90,216)
Other noncash items	(39,599)	6,725	25,102
Change in operating assets and liabilities			
Accounts receivable, net	(28,206)	(47,331)	36,653
Income taxes receivable	(5,953)	29,406	(5,878)
Inventories	33,059	(137,401)	(26,281)
Prepaid expenses	1,447	(3,415)	(3,874)
Other current assets	14,291	1,957	(14,270)
Accounts payable	46,038	136,296	128,927
Interest payable	10,842	(1,768)	11,999
Income taxes payable	(9,580)	(7,623)	4,007
Other current liabilities	(38,320)	61,210	(40,586)
Net cash provided by operating activities	1,837,577	1,529,714	1,285,023
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	95,564	819,044	313,780
Payments for acquisition, net of cash acquired	(297,092)	—	—
Investment in unconsolidated subsidiary	—	(89,620)	(72,864)
Additions to oil and gas properties	(2,758,073)	(1,926,965)	(1,011,442)
Additions to other assets and other property and equipment, net	(296,809)	(363,246)	(184,330)
Net cash used in investing activities	(3,256,410)	(1,560,787)	(954,856)
Cash flows from financing activities:			
Borrowings under long-term debt	1,776,618	196,616	292,342
Principal payments on long-term debt	(612,001)	(294,883)	(475,252)
Proceeds from issuance of common stock, net of issuance costs	—	484,160	—
Proceeds from issuance of partnership common units, net of issuance costs	—	122,976	—
Contributions from noncontrolling interests	—	—	1,151
Distributions to noncontrolling interests	(35,903)	(26,702)	(26,837)
Payments of other liabilities	(1,153)	(901)	(21,329)

Exercise of long-term incentive plan stock options and employee stock purchases	7,271	3,696	7,375
Purchase of treasury stock	(63,325)	(40,355)	(14,039)
Excess tax benefit (provision) from share-based payment arrangements	58,486	31,087	(153)
Payment of financing fees	(9,227)	(8,741)	(145)
Dividends paid	(10,021)	(9,556)	(9,488)
Net cash provided by (used in) financing activities	1,110,745	457,397	(246,375)
Net increase (decrease) in cash and cash equivalents	(308,088)	426,324	83,792
Cash and cash equivalents, beginning of period	537,484	111,160	27,368
Cash and cash equivalents, end of period	$229,396	$537,484	$111,160

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012, 2011 and 2010

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company ("Pioneer" or "the Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company in the United States, with field operations in the Permian Basin in West Texas, the Eagle Ford Shale play in South Texas, the Barnett Shale Combo play in North Texas, the Raton field in southeastern Colorado, the Hugoton field in southwest Kansas, the West Panhandle field in the Texas Panhandle and Alaska. The Company's objective is to maximize shareholder investment returns by maintaining financial flexibility, capital allocation discipline and enhancing net asset value through accretive drilling programs, joint ventures and acquisitions.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. In accordance with generally accepted accounting principles in the United States ("GAAP"), the Company proportionately consolidates certain affiliate partnerships that are less than wholly-owned and are involved in oil and gas producing activities. All material intercompany balances and transactions have been eliminated.

Certain reclassifications have been made to the 2011 and 2010 financial statement and footnote amounts in order to conform them to the 2012 presentations.

On May 6, 2008, the Company recognized a noncash gain on the sale of common units of Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest," a majority-owned and consolidated subsidiary) as a component of additional paid-in capital in stockholders' equity. In accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 740 Income Taxes, deferred income taxes of $49.1 million should be recognized for the future tax effects arising from the noncash gain on the sale of the Pioneer Southwest common units, with a corresponding decrease to additional paid-in capital. The Company recorded the deferred income taxes associated with this transaction in 2012. The effect of this adjustment is immaterial to the accompanying financial statements.

The accompanying consolidated balance sheet as of December 31, 2011 has been revised for a change in the classification of deferred income taxes associated with the Company's unrealized current derivative net gains as of December 31, 2011. The noncash revisions resulted in a $77.0 million decrease in current deferred tax assets, a $57.7 million increase in current deferred tax liabilities and a $134.7 million decrease in noncurrent deferred tax liabilities from the amounts previously reported at December 31, 2011. These revisions were made to appropriately reflect the impact on deferred income taxes based on the expected settlement periods related to derivatives, which remained subject to market risk as of December 31, 2011.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties and impairment of goodwill and proved and unproved oil and gas properties, in part, is determined using estimates of proved, probable and possible oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved, probable and possible reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Actual results could differ from the estimates and assumptions utilized.

Cash and cash equivalents. The Company's cash and cash equivalents include depository accounts held by banks and marketable securities with original issuance maturities of 90 days or less.

Accounts receivable. As of December 31, 2012 and 2011, the Company had accounts receivable – trade, net of allowances for bad debts, of $316.9 million and $276.0 million, respectively. The Company's accounts receivable –

trade are primarily comprised of oil and gas sales receivable, joint interest receivables and other receivables for which the Company does not require collateral security.

As of December 31, 2012 and 2011, the Company's allowances for doubtful accounts totaled \$1.5 million and \$1.1 million, respectively. The Company establishes allowances for bad debts equal to the estimable portions of accounts and notes receivables for which failure to collect is considered probable. The Company estimates the portions of joint interest receivables for which failure to collect is probable based on percentages of joint interest receivables that are past due. The Company estimates the portions of other receivables for which failure to collect is probable based on the relevant facts and circumstances surrounding the receivable. Allowances for doubtful accounts are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable.

Inventories. The Company's inventories consist of materials and supplies and commodities. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, proppant used to fracture-stimulate oil and gas wells, chemicals, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a first-in, first-out cost basis. "Market," in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. Valuation reserve allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supply inventories in the Company's consolidated balance sheets and as other expense in the accompanying consolidated statements of operations.

Commodities inventories are carried at the lower of average cost or market, on a first-in, first-out basis. The Company's commodities inventories consist of oil held in storage and natural gas liquids ("NGLs") and gas pipeline fill volumes. Any valuation allowances of commodities inventories are recorded as reductions to the carrying values of the commodities inventories included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations.

The following table presents the Company's materials and supplies and commodities inventories as of December 31, 2012 and 2011:

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Materials and supplies (a)	$258,962	$297,910
Commodities	5,446	4,453
Less: Noncurrent materials and supplies (b)	(67,352)	(60,754)
	$197,056	$241,609

(a) As of December 31, 2012 and 2011, the Company's materials and supplies inventories were net of valuation reserve allowances of $4.6 million and $0.9 million, respectively.
(b) Included in other noncurrent assets in the Company's accompanying consolidated balance sheet.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company capitalizes interest on expenditures for significant development projects, generally when the underlying project is sanctioned, until such projects are ready for their intended use. For large development projects requiring significant upfront development costs to support the drilling and production of a planned group of wells, the Company continues to capitalize interest on the portion of the development costs attributable to the planned wells yet to be drilled.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well.
(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly.

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012, 2011, and 2010

Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found sufficient proved reserves to sanction the project or is noncommercial and is charged to exploration and abandonments expense. See Note F for additional information regarding the Company's suspended exploratory well costs.
The Company owns interests in four gas processing plants and ten treating facilities. The Company is the operator of two of the gas processing plants and all ten of the treating facilities. The Company's ownership interests in the gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. Third party revenues generated from the processing plants and treating facilities for the three years ended December 31, 2012, 2011 and 2010 were $39.4 million, $46.0 million and $34.0 million, respectively. Third party expenses attributable to the processing plants and treating facilities for the same respective periods were $27.1 million, $22.7 million and $14.3 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.
The capitalized costs of proved properties are depleted using the unit-of-production method based on proved reserves. Costs of sig