PIONEER NATURAL RESOURCES CO
Form 10-K
February 26, 2010
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2009**

**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 | 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** x **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** x

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** x **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** x **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** | x | **Accelerated filer** | ¨ |
| **Non-accelerated filer** | ¨ (Do not check if a smaller reporting company) | **Smaller reporting company** | ¨ |

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

| | |
|---|---|
| **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** | **$ 2,891,492,634** |
| **Number of shares of Common Stock outstanding as of February 23, 2010** | **115,550,322** |

**DOCUMENTS INCORPORATED BY REFERENCE:**

(1) Portions of the definitive proxy statement for Annual Meeting of Shareholders to be held during May 2010 as referenced in Part III of this report.

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**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.

*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.

*IPO* means initial public offering.

*LIBOR* means London Interbank Offered Rate, which is a market rate of interest.

*LNG* means liquefied natural gas.

*MBbl* means one thousand Bbls.

*MBOE* means one thousand BOEs.

*Mcf* means one thousand cubic feet and is a measure of natural gas volume.

*MMBbl* means one million Bbls.

*MMBOE* means one million BOEs.

*MMBtu* means one million Btus.

*MMcf* means one million cubic feet.

*MMcfpd* means one million cubic feet per day.

*Mont Belvieu posted-price* means the daily average natural gas liquids components as priced in *Oil Price Information Service* ( OPIS ) in the table U.S. and Canada LP Gas Weekly Averages at Mont Belvieu, Texas.

*NGL* means natural gas liquid.

*NYMEX* means the New York Mercantile Exchange.

*NYSE* means the New York Stock Exchange.

*Pioneer* or the *Company* means Pioneer Natural Resources Company and its subsidiaries.

*Pioneer Southwest* means Pioneer Southwest Energy Partners L.P. and its subsidiaries.

*proved reserves* means 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 geosciences and engineering data.

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

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

(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 is based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing 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.

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*U.S.* means United States of America.

*VPP* means volumetric production payment.

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 (the Report ) contain forward-looking statements that involve risks and uncertainties. When used in this document, the words believes, plans, expects, anticipates, intends, continue, may, will, could, should, future, potential, estimate, or the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company and its subsidiaries ( Pioneer or the Company ) are intended to identify forward-looking statements. 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, 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.*

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# PART I

## Item 1. Business

### General

Pioneer is a Delaware corporation whose common stock is listed and traded on the NYSE. The Company is a large independent oil and gas exploration and production company with current operations in the United States, South Africa and Tunisia. Pioneer is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries.

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; Midland, Texas; London, England; Capetown, South Africa and Tunis, Tunisia. At December 31, 2009, the Company had 1,888 employees, 1,151 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 Report 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, net asset value and net asset value per share. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline while enhancing net asset value per share through accretive drilling programs, acquisitions, debt reduction, dividend distributions and share repurchases. These strategies are anchored by the Company s long-lived Spraberry oil field and Hugoton, Raton and West Panhandle gas fields, which have an estimated remaining productive life in excess of 40 years. Underlying these fields are approximately 88 percent of the Company s proved oil and gas reserves as of December 31, 2009.

### 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 experienced personnel who make prudent capital investment decisions, embrace technological innovation and are focused on price and cost management.

***Petroleum industry.*** Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same time period, North American gas supply increased as a result of the rise in domestic unconventional gas production. The combination of lower energy demand due to the economic slowdown and higher North American gas supply resulted in significant declines in oil, NGL and gas prices. While oil and NGL prices started to steadily improve beginning in the second quarter of 2009, gas prices remained volatile throughout 2009 due to high storage levels and increasing gas supply. The outlook for a worldwide economic recovery in 2010 remains uncertain and, therefore, the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices during 2010 will continue to be volatile.

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For the several years preceding the 2008 economic slowdown, the petroleum industry had generally been characterized by volatile but upward-trending oil, NGL and gas commodity prices. During that period, world oil prices increased in response to increases in demand from developing economies and the perceived threat of supply disruptions in the Middle East, Nigeria, Venezuela and other areas. In 2007 and the first half of 2008, oil prices increased due to supply uncertainty surrounding Middle East conflicts and increasing world demand for both oil and refined products. A significant increase in refinery outages led to tightness in products markets, which was responsible for oil price strength throughout much of 2007 and the early part of 2008. North American gas prices increased during the first half of 2008 as a result of reduced inventory levels and a perceived shortage of North American gas supply and an anticipation that the United States would become a larger importer of LNG, which was selling at a substantial premium to United States gas prices in the world market. However, by mid-year 2008 it became increasingly apparent that the capital investment in gas drilling and discoveries of significant gas reserves in United States shale plays would be more than sufficient to meet the Unites States demand. Coupled with the economic slowdown experienced in the second half of 2008, the increased supply of gas resulted in a sharp decline in North American gas prices.

Significant factors that the Company expects to impact 2010 commodity prices include: the effect of economic stimulus initiatives being implemented in the United States and worldwide in response to the worldwide economic slowdown; developments in the issues affecting the Middle East in general; demand of 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 gas supply and demand fundamentals.

To mitigate the impact of commodity price volatility on the Company s net cash provided by operating activities and its net asset value, Pioneer utilizes commodity derivative contracts. Although the Company has entered into derivative contracts on a large portion of its forecasted production through 2012, 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 internally-generated cash flows would be reduced for affected periods. Significant or extended price declines could also adversely affect the amount of oil, NGL and gas that the Company can produce economically. The duration, timing and magnitude of any period of lower commodity prices cannot be predicted. 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 J of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for information regarding the effect on oil, NGL and gas revenues during 2009, 2008 and 2007 from the Company s derivative price risk management activities and the Company s open derivative positions at December 31, 2009.

***The Company.*** The Company s asset base is anchored by the Spraberry oil field located in West Texas, the Raton gas field located in southern Colorado, the Hugoton gas field located in southwest Kansas and the West Panhandle gas field located in the Texas Panhandle. Complementing these areas, the Company has exploration and development opportunities and/or oil and gas production activities in the Eagle Ford and Edwards Trend areas of South Texas, the Barnett Shale area of North Texas and Alaska, and internationally in South Africa and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well- balanced among oil, NGLs and gas, and that are also well-balanced among long-lived, dependable production, lower-risk exploration and development opportunities and a limited number of higher-impact exploration opportunities. Additionally, the Company has a team of dedicated employees that represent the professional disciplines and sciences that will 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 United States and foreign subsidiaries that explore for, develop and produce proved reserves. Production operations are principally located domestically in Texas, Kansas, Colorado and Alaska, and internationally in South Africa and Tunisia.

***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. During the year ended December 31, 2009, the Company s average daily production, on a BOE basis, increased three percent as compared to 2008 as a

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result of a full year of production from the successful development drilling programs in the Spraberry field during 2008, the addition of the Sable gas well during the fourth quarter of 2008 to production from the South Coast gas project in South Africa, development activities in Tunisia and a seven percent decrease in scheduled deliveries of VPP volumes. Production, price and cost information with respect to the Company s properties for 2009, 2008 and 2007 is set forth under 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, 2009, the Company drilled 1,203 gross (1,154 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 $2.4 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, 2009 include proved undeveloped reserves and proved developed reserves that are behind pipe of 186 MMBbls of oil, 66 MMBbls of NGLs and 870 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 portfolio of lower-risk exploration opportunities complemented by a limited number of higher-impact exploration opportunities. 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.

***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 feature producing properties and provide exploration/exploitation opportunities. During 2009, 2008 and 2007, the Company invested $88.9 million, $137.6 million and $536.7 million, respectively, of acquisition capital to purchase proved oil and gas properties, including additional interests in its existing assets, and to acquire new prospects for future exploitation and exploration activities. See Note C of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for a description of the Company s acquisitions of proved oil and gas properties during 2009, 2008 and 2007.

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.*** 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. See Notes N and V 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 during 2009, 2008 and 2007.

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.

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**Operations by Geographic Area**

The Company operates in one industry segment, that being oil and gas exploration and production, in three geographic areas. See Note R of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for geographic operating segment information, including results of operations and segment assets.

**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 the index or spot prices, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. See Qualitative Disclosures in Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional discussion of operations and price risk.

***Significant purchasers.*** During 2009, the Company s significant purchasers of oil, NGLs and gas were Plains Marketing LP (10 percent), ConocoPhillips (9 percent), Occidental Energy Marketing, Inc. (7 percent), Enterprise Products Partners L.P. (6 percent) and Oneok Resources (5 percent). The Company believes that the loss of any one purchaser would not have a material adverse effect on its ability to sell its oil, NGL and gas production.

***Derivative risk management activities.*** The Company from time to time utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company s annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. As of January 31, 2009, the Company discontinued hedge accounting and began accounting 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 J 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 losses during 2009, 2008 and 2007, as well as the Company s open and terminated commodity derivative positions at December 31, 2009.

**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 to acquire 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 could have an adverse effect on the market price of the Company s commons stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

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***Environmental matters and regulations.*** The Company s operations are subject to stringent and complex foreign, federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- enjoin some or all of the operations of facilities deemed in non-compliance 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; 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 United States Congress and state legislatures, federal and state regulatory agencies and foreign government and agencies frequently revise environmental laws and regulations, and the clear 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 impact on the Company s operating costs.

The following is a summary of some of the existing laws, rules and regulations to which the Company s business operations are subject.

*Waste handling.* The Resource Conservation and Recovery Act ( RCRA ) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the 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. Certain processes used to produce oil and gas may enhance the radioactivity of NORM, which may be present in oilfield wastes. 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 Comprehensive Environmental Response, Compensation and Liability Act ( CERCLA ), also known as the Superfund law, imposes 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 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 disposal. In addition, some of the Company s properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under the Company s control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by the Company. These 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.

*Water discharges and use.* The Clean Water Act (the CWA ) and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by 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. Spill prevention, control and countermeasure 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 non-compliance 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.

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, the United States Congress is considering amending the SDWA to require additional regulation of chemicals used by the oil and gas industry in the hydraulic fracturing process, and some states are considering similar regulations.

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 recent 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 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 Federal Clean Air Act (the CAA ) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions; obtain or strictly comply with air permits containing various emissions and operational limitations; or utilize specific emission control technologies to limit emissions of certain air pollutants. 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 non-compliance with air permits or other requirements of the federal 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. In addition, 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. Gas and oil exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

The Texas Commission on Environmental Quality (the TCEQ ) recently concluded an analysis of air emissions of third-party operators in the Barnett Shale area in response to reported concerns about high concentrations of benzene in the air near drilling sites and gas processing facilities. The TCEQ s investigation revealed elevated levels of benzene and other emissions at certain locations. The agency has announced that it will continue monitoring emissions and will investigate all complaints about oil and gas activities in the Barnett Shale area within 12 hours of receipt. The agency s investigations could lead to more stringent air permitting, increased regulation and possible enforcement actions against producers, including Pioneer, in the Barnett Shale area. In addition, environmental groups have advocated for increased regulation in the Barnett Shale area, and at least one state representative has advocated a moratorium on the issuance of drilling permits for new gas wells in the area. Any adoption of laws, regulations, orders or other legally enforceable mandates governing gas drilling and operating activities in the Barnett Shale that result in more stringent drilling or operating conditions or limit or prohibit the drilling of new gas wells for any extended period of time could increase the Company s costs and/or reduce its production, which could have a material adverse effect on the Company s results of operations and cash flows.

*Health and safety.* The Company s operations are subject to the requirements of the federal Occupational Safety and Health Act (the OSH Act ) and comparable state statutes. These laws and the related regulations strictly govern the protection of the health and safety of employees. The OSH Act 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. The Company believes that it is in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

*Global warming and climate change.* On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to human 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. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles and that could also lead to the imposition of GHG emission limitations in CAA permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company s equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with the Company s operations or could adversely affect demand for the oil, NGL and gas that the Company produces.

Also, on June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009 ( ACESA ), which is also known as the Waxman-Markey cap-and-trade legislation. The purpose of ACESA is to control and reduce emissions of greenhouse gases in the United States. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances permitted by ACESA declines each year, the

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cost or value of allowances would be expected to escalate significantly. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and gas. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law.

In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Finally, other nations have been seeking to reduce emissions of GHGs pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of GHGs to below 1990 levels by 2012. Depending on the particular jurisdiction in which the Company s operations are located, it could be required to purchase and surrender allowances for GHG emissions resulting from the Company s operations.

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 instance, the Company did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2009. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2010. However, 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.

***Other regulation of the oil and gas industry.*** The oil and gas industry is regulated by numerous foreign, 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 departments and agencies, foreign, federal and state, 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 transporting its production to market, 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. For example, the Company s properties located in Colorado are subject to the authority of the Colorado Oil & Gas Conservation Commission (the COGCC ). The COGCC has recently promulgated new rules that are likely to increase the Company s costs of permitting and environmental compliance, and to extend waiting periods for the acquisition of permits.

*Development and production.* Development and production operations are subject to various types of regulation at foreign, 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 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

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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 to 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. Foreign, federal and state regulations govern the price and terms for access to gas pipeline transportation. The interstate transportation and sale for resale 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 ). The FERC s regulations for interstate gas transmission in some circumstances may also affect the intrastate transportation of gas. As a result of initiatives like FERC Order No. 636 ( Order 636 ), issued in April 1992, the interstate gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all gas supplies. In many instances, the results of Order 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines traditional role as wholesalers of gas in favor of providing only storage and transportation services.

In August 2005, Congress enacted the Energy Policy Act of 2005 ( EPAct 2005 ). Among other matters, EPAct 2005 amends the Natural Gas Act ( NGA ) to make it unlawful for any entity, including otherwise non-jurisdictional producers such as the Company, 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 the FERC, in contravention of rules prescribed by the FERC. The FERC s rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the 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 the FERC authority to impose civil penalties for violations of the NGA up to $1.0 million per day per violation. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities 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, the FERC issued rules ( Order 704 ) requiring that 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 during a calendar year must annually report such sales and purchases to the FERC. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist the FERC in monitoring those markets and in detecting market manipulation.

Although gas prices are currently unregulated, Congress historically has been active in the area of gas regulation. The Company cannot predict whether new legislation to regulate gas or gas prices might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on the Company s operations. Sales of condensate and gas liquids are not currently regulated and are made at market prices.

*Gas gathering.* 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 impacted by the rates charged by such third parties for gathering services. To the extent that changes in foreign, federal and/or state regulation affect the rates charged for gathering services, the Company also may be affected by such changes. Accordingly, the Company does not anticipate that the Company would be affected any differently than similarly situated gas producers.

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## 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 Pioneer s ability to implement business plans or complete development projects 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;
- weather conditions;
- overall domestic and global political and economic conditions;
- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;
- the effect of LNG deliveries to 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, oil prices reached record levels in July 2008 of $145.29 per Bbl before declining to $33.87 per Bbl in December, while gas prices reached $13.58 per Mcf before declining to $5.29 per Mcf over the same period. During 2009, oil prices increased from a low of $33.98 per Bbl in February to a high of $81.37 per Bbl in October while gas prices declined from $6.07 per Mcf in January to $2.51 per Mcf in September. 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. Such 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. 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 planned.

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***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 mark-to-market accounting treatment, and the changes in fair market value of the contracts will be reported in the Company s statement of operations each quarter, which may result in significant 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 revenue and liquidity when prices decline, as occurred in late 2008 and during 2009.

***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 as a result of a variety of factors, including:

- unexpected drilling conditions;
- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- restricted access to land for drilling or laying pipelines; and
- costs of, or shortages or delays in the delivery of, drilling rigs, equipment and personnel.

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 2010. 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. Although the Company has experienced some decrease in these costs over the past year, such decreases could be short-lived. A return to the trends of increasing demand and costs in the future may affect the Company s profitability, cash flow and ability to complete development projects as scheduled and on budget.

***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 s having to make substantial downward adjustments to the Company s 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 will be required to reduce the carrying value of the proved properties to their estimated fair value. For example, during 2009, the Company recognized impairment charges of $21.1 million due to the impairment of the Company s net assets in the Uinta/Piceance areas, 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, 2009, the Company carried unproved property costs of $236.7 million. GAAP requires periodic evaluation of these costs on a project-by-project basis. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, 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 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 been an important element of 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 impact 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 may be unable to dispose of nonstrategic assets on attractive terms, and may be required to retain liabilities for certain matters.***

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 nonstrategic assets, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to the Company. Sellers typically retain certain liabilities or indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale 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 current economic outlook has affected the level of sales activity for oil and gas properties. The higher cost of credit has limited third parties ability to acquire properties, and the potential value of the Company s properties is likely to decline if adverse economic conditions continue.

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***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, 2009, the Company carried goodwill of $309.3 million associated with its United States reporting unit. 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) future reserve adjustments both positive and negative, (b) results of drilling activities, (c) changes in management s outlook on 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 s gas processing operations are subject to operational risks, which could result in significant damages and the loss of revenue.***

As of December 31, 2009, the Company owned interests in four gas processing plants and eleven treating facilities. The Company operates two of the gas processing plants and all eleven 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 misoperation 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 substantial losses to the Company and unforeseen interruptions to the Company s operations for which the Company may not be adequately insured.***

The Company s operations 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 ruptures and discharges of toxic gases;
- high costs, shortages or delivery delays of equipment, labor or other services;
- 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.

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. For example, in 2008, damage caused by Hurricanes Gustav and Ike to a third-party facility that fractionates NGLs from a portion of the Company s production resulted in a portion of the Company s production being shut in or curtailed from early September to mid-November 2008 while repairs and maintenance to the facility were being completed.

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***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. 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 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, gas gathering, transmission, storage and processing facilities to market its oil and gas production.***

The marketing of oil 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 and refining facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, or if these systems were unavailable to the Company, 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, transmit and sell its oil 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 transmission, storage or processing facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist.

***The nature of the Company s assets exposes it to significant costs and liabilities with respect to environmental and operational safety matters.***

The oil and gas business is subject to environmental hazards such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of United States federal, state and local, as well as foreign 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 matters and regulations above for additional discussion related to environmental risks.

No assurance can be given that existing or future environmental laws 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. Pollution and similar environmental risks generally are not fully insurable.

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

The Company is a borrower under fixed rate senior notes, senior convertible notes and a credit facility. The terms of the Company s borrowings under the senior notes, senior convertible notes and the credit facility 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 F 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, 2009 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. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the Company s debt credit ratings.

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***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 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, local and foreign laws and regulations. For example, the Company s properties located in Colorado are subject to the authority of the Colorado Oil & Gas Conservation Commission (the COGCC ), which recently passed certain rules that will increase the length of time needed to obtain certain permits and will increase the Company s costs of permitting and environmental compliance. In addition, in connection with the Company s CBM operations in the Raton Basin in Colorado, the Colorado Supreme Court recently 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 international operations may be adversely affected by economic, political and other factors.***

At December 31, 2009, two percent of the Company s proved reserves were located outside the United States. The success and profitability of international operations may be adversely affected by risks associated with international activities, including:

- economic and labor conditions;
- war, terrorist acts and civil disturbances;
- political instability;
- loss of revenue, property and equipment as a result of actions taken by foreign countries where the Company has operations, such as expropriation or nationalization of assets and renegotiation, modification or nullification of existing contracts;
- changes in taxation policies (including host-country import-export, excise and income taxes and United States taxes on foreign subsidiaries);

laws and policies of the United States and foreign jurisdictions affecting foreign investment, trade and business conduct; and

changes in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be denominated.

In some cases, the market for the Company s production in foreign countries is limited to some extent. For example, all of the Company s gas and condensate production from the South Coast Gas project in South Africa is currently committed by contract to a single, government-affiliated gas-to-liquids facility. If such facility ceased to purchase the gas because of an unforeseen event, it might be difficult to find an alternative market for the production, and if such a market were secured, the price received by the Company might be less than that provided under its current gas sales contract. See Qualitative Disclosures Foreign currency, operations and price risk in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note B of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for information regarding other risks associated with the Company s international operations.

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

- the quantities of oil, NGLs and gas that are ultimately recovered;
- the production and operating costs incurred;
- 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.

The Company reports all proved reserves held under concessions utilizing the economic interest method, which excludes the host country s share of proved reserves. Estimated quantities reported under the economic interest method are subject to fluctuations in commodity prices and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices.

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 occur, such as facility or equipment malfunctions, adverse weather effects, or downturns in commodity prices or significant increases in costs, which could make certain drilling activities or production uneconomical.

***The Company may be unable to complete its plans to repurchase its common stock.***

The Board of Directors (the Board ) approves share repurchase programs and sets limits on the price per share at which Pioneer s common stock can be repurchased. From time to time, the Company may not be permitted to repurchase its stock during certain periods because of scheduled and unscheduled trading blackouts. Additionally, business conditions and availability of capital may dictate that repurchases be suspended or canceled. As a result, there can be no assurance that additional repurchase programs will be commenced and, if so, that they will be completed.

***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 Energy Partners L.P., a publicly-traded limited partnership formed by the Company to own 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 the partnership. 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.

***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 markets, the availability of credit and the equity markets have improved during 2009, the economic outlook for 2010 remains uncertain. To the extent that purchasers of the Company s production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to the Company. 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.

***The Company may not be able to obtain funding, obtain funding on acceptable terms or obtain funding under its current credit facility in the event of a deterioration of the credit and capital markets, which could hinder or prevent the Company from meeting its future capital needs.***

During 2009, access to the debt and equity capital markets improved. However, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets was higher than historical levels as many lenders and institutional investors increased interest rates, enacted tighter lending standards and limited the amount of funding available to borrowers.

If these events were to recur, the Company could be unable to obtain adequate funding under its current credit facility because (i) the Company s lending counterparties may be unwilling or unable to meet their funding obligations or (ii) the amount the Company may borrow under its current credit facility could be reduced as a result of lower oil, NGL or gas prices, declines in reserves, stricter lending requirements or regulations, or for other reasons. For example, the Company s credit facility requires that the Company maintain a specified ratio of the net present value of the Company s oil and gas properties to total debt, with the variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) being subject to adjustment by the lenders. Due to these factors, the Company cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, the Company may be unable to implement its business plans or otherwise take advantage of business opportunities or respond to competitive pressures any of which could have a material adverse effect on the Company s production, revenues and results of operations.

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

Concerns over the worldwide economic outlook, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased volatility and diminished expectations for the global economy. These factors, combined with volatile oil prices, declining business and consumer confidence and increased unemployment, precipitated a worldwide recession. Concerns about global economic growth have had a significant adverse effect on global financial markets and commodity prices, both of which contributed to a decline in the Company s share price and corresponding market capitalization during 2008. If the economic climate in the United States or abroad deteriorates, demand for petroleum products could further diminish, which could further depress the prices at which the Company can 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.***

President Obama s proposed Fiscal Year 2011 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Each of these changes is proposed to be effective for taxable years beginning, or in the case of costs described in (ii) and (iv), costs paid or incurred, after December 31, 2010. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such change could negatively affect the Company s financial condition and results of operations.

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

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to human 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. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company s equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with the Company s operations or could adversely affect demand for the oil, NGL and gas that the Company produces.

Also, on June 26, 2009, the United States House of Representatives approved adoption of ACESA. The purpose of which is to control and reduce emissions of greenhouse gases in the United States. The United States Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. It is not possible at this time to predict with certainty whether climate change legislation will be enacted, but any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require the Company to incur increased operating costs and could have an adverse effect on demand for the oil, NGLs and gas it produces. See Competition, Markets and Regulations in Item 1. Business.

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***The adoption of derivatives legislation by the United States Congress could have an adverse effect on the Company s ability to use derivative instruments to reduce the effect of commodity price risk associated with its business.***

The United States Congress currently is considering comprehensive financial reform legislation that includes restrictions on certain transactions involving derivatives. This legislation also would provide the Commodity Futures Trading Commission ( CFTC ) with express authority to impose position limits related to energy commodities, such as oil and gas. Separately, the CFTC is proposing regulations to set position limits for certain futures and option contracts in the major energy markets. Although it is not possible at this time to predict whether or when the CFTC may adopt rules or the United States Congress may act on derivatives legislation, any laws or regulations that may be adopted could have an adverse effect on the Company s ability to utilize derivative instruments to reduce the effect of commodity price risk associated with its business.

***Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.***

The United States Congress is currently considering legislation to amend the federal Safe Drinking Water Act to regulate chemicals used by the oil and gas industry in the hydraulic fracturing process, and some other states are considering similar regulations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and gas production. Sponsors of bills currently pending before the United States Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation also would require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory agencies, which could make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase the Company s costs of compliance and doing business.

***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. The Company has also adopted a shareholder rights plan. 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.

**Item 1B. Unresolved Staff Comments**

None.

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**Item 2. Properties**

**Reserve Rule Changes**

During 2009, the SEC issued its final rule on the modernization of oil and gas reporting (the Reserve Ruling ) and the Financial Accounting Standards Board (the FASB ) issued Accounting Standards Update No. 2010-03 ( ASU 2010-03 ) Extractive Industries Oil and Gas, which aligns the estimation and disclosure requirements of FASB Accounting Standards CodificationTopic 932 with the Reserve Ruling. The Reserve Ruling and ASU 2010-03 are effective for Annual Reports on Form 10-K for fiscal years ending on or after December 31, 2009. The key provisions of the Reserve Ruling and ASU 2010-03 are as follows:

Expanding the definition of oil- and gas-producing activities to include the extraction of saleable hydrocarbons, in the solid, liquid or gaseous state, from oil sands, coalbeds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction;

Amending the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices;

Adding to and amending other definitions used in estimating proved oil and gas reserves, such as reliable technology and reasonable certainty ;

Broadening the types of technology that a reporter may use to establish reserves estimates and categories; and

Changing disclosure requirements and providing formats for tabular reserve disclosures.

**Reserve Estimation Procedures and Audits**

The information included in this Report about the Company s proved reserves as of December 31, 2009, 2008 and 2007, which are located in the United States, South Africa and Tunisia, is based on evaluations prepared by (i) the Company s engineers and audited by Netherland, Sewell & Associates, Inc. ( NSAI ), with respect to the Company s major properties, and (ii) the Company s engineers, with respect to all other properties. The Company has no oil and gas reserves from non-traditional sources. Additionally, the Company does not provide optional disclosure of probable or possible reserves.

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

The management of Pioneer s oil and gas assets is decentralized geographically by individual asset teams who are responsible for the oil and gas activities in each of the Company s Permian Basin, Rockies, Mid-Continent, South Texas (which is now being further decentralized stratigraphically into the South Texas - Eagle Ford Shale and South Texas - Edwards asset teams), Barnett Shale, Alaska and Africa asset teams (the Asset Teams ). The Company s Asset Teams are each staffed with reservoir engineers and geoscientists who prepare reserve estimates for the assets that they manage at the end of each calendar quarter 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 Chief Operating Officer ( COO ) and management committee ( MC ). The Company s MC is comprised of its Chief Executive Officer, COO, Chief Financial Officer and other Executive Vice Presidents. Asset Teams reserve estimates are reviewed by the asset team reservoir engineers before being submitted to the Director of the WWR and are summarized in reserve reconciliations that quantify reserve changes represented by revisions of previous estimates, purchases of minerals-in-place, 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. The MC reviews the reserve estimates and any differences with NSAI (for the portion of the reserves audited by NSAI) on a consolidated basis before these estimates are approved. The engineers and geoscientists who participate in the reserve estimation and disclosure process attended training on the Reserve Ruling by external consultants and/or through internal Pioneer programs. Additionally, the WWR has prepared and maintains an internal document 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.

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*Proved reserves audits.* The reserve audits performed by NSAI in the aggregate represented 93 percent, 87 percent and 86 percent of the Company s 2009, 2008 and 2007 proved reserves, respectively; and, 86 percent, 80 percent and 80 percent of the Company s 2009, 2008 and 2007 associated pre-tax present value of proved reserves discounted at ten percent, respectively.

NSAI follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers ( 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 generally accepted petroleum engineering and evaluation principles.

> The estimation of proved 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.

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

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

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

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*Qualifications of reserves preparers and auditors.* The WWR is staffed by petroleum engineers with extensive industry experience and is managed by the Director of 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 Board of the Society of Petroleum Engineers. The WWR Director s qualifications include 32 years of experience as a petroleum engineer, with 25 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 ( CFA ) and a member of the Oil and Gas Reserves Committee of the Society of Petroleum Engineers.

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-002699. 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 30 years of practical experience in petroleum engineering, including 29 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 the Society of Petroleum Engineers.

*Technologies used in reserves estimates.* The Company uses reliable technologies to establish additions to reserve estimates, The Company uses includes a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data to calculate reserves estimates.

**Proved reserves**

The Company s proved reserves totaled 898.6 MMBOE, 959.6 MMBOE and 963.8 MMBOE at December 31, 2009, 2008 and 2007, respectively, representing $3.3 billion, $3.2 billion and $9.0 billion, respectively, of Standardized Measure. The Company s proved reserves include field fuel, which is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point. The following table shows the changes in the Company s proved reserve volumes by geographic area during the year ended December 31, 2009 (in MBOE):

| | Production | Extensions and Discoveries | Purchases of Minerals-in-Place | Sales of Minerals-in-Place | Revisions of Previous Estimates |
|---|---|---|---|---|---|
| United States | (41,088) | 14,785 | | (2,319) | (25,660) |
| South Africa | (1,690) | | | | (703) |
| Tunisia | (2,485) | | | | (1,780) |
| Total | (45,263) | 14,785 | | (2,319) | (28,143) |

*Production.* Production volumes include 3,004 MBOE of field fuel.

*Extensions and discoveries.* Extensions and discoveries are primarily comprised of discoveries in the Company s South Texas Edwards Trend and extension drilling in the North Texas Barnett Shale play, the Spraberry field and Alaska.

*Sales of minerals-in-place.* Sales of minerals-in-place are principally related to the divestment of the Company s Gulf of Mexico shelf and Mississippi properties. See Note N of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

*Revisions of previous estimates.* Revisions of previous estimates are comprised of 65 MMBOE of negative price revisions offset by 37 MMBOE of positive technical revisions. The Company s proved reserves at December 31, 2009 were determined using the average of the first-day-of-the-month commodity prices during the 12-month

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period ending December 31, 2009 of $61.14 per barrel of oil and $3.87 per Mcf of gas, compared to $44.60 per barrel of oil and $5.71 per Mcf of gas as of December 31, 2008.

*Tabular proved reserves disclosures.* On a BOE basis, 58 percent of the Company s total proved reserves at December 31, 2009 were proved developed reserves. Based on reserve information as of December 31, 2009, and using the Company s production information for the year then ended, the reserve-to-production ratio associated with the Company s proved reserves was in excess of 20 years on a BOE basis. The following table provides information regarding the Company s proved reserves by geographic area as of and for the year ended December 31, 2009:

| | **Summary of Oil and Gas Reserves as of December 31, 2009 Based on Average Fiscal-Year Prices** | | | | |
|---|---|---|---|---|---|
| | **Oil (MBbls)** | **NGLs (MBbls)** | **Gas (MMcf) (a)** | **MBOE (b)** | **Standardized Measure (b)** |
| | | | **(in thousands)** | | |
| Developed: | | | | | |
| United States | 135,568 | 93,015 | 1,671,052 | 507,092 | $ 2,512,221 |
| South Africa | 217 | | 25,790 | 4,516 | 71,905 |
| Tunisia | 8,478 | | 22,880 | 12,291 | 169,035 |
| | 144,263 | 93,015 | 1,719,722 | 523,899 | 2,753,161 |
| Undeveloped: | | | | | |
| United States | 180,025 | 63,818 | 779,079 | 373,689 | 558,628 |
| Tunisia | 1,048 | | | 1,048 | 18,765 |
| | 181,073 | 63,818 | 779,079 | 374,737 | 577,393 |
| | 325,336 | 156,833 | 2,498,801 | 898,636 | $ 3,330,554 |

(a) The gas reserves contain 310,463 MMcf of gas that will be produced and utilized as field fuel.

(b) See Unaudited Supplementary Information included in Item 8. Financial Statements and Supplementary Data for information regarding the impact of the Reserve Ruling and ASU 2010-03 on the Company s proved reserves and Standardized Measure.

*Proved undeveloped reserves.* As of December 31, 2009, the Company has 4,582 proved undeveloped well locations (all of which are expected to be developed within the five years ended December 31, 2014), representing a decrease of 395 proved undeveloped well locations (eight percent) since December 31, 2008. The decrease in proved undeveloped well locations during 2009 is primarily attributable to decreases in Raton basin well locations due to gas price revisions that rendered certain locations uneconomic under proved reserve pricing guidelines and 114 undeveloped well locations that were drilled and completed as developed wells during 2009, at a net cost of $76.3 million. During 2008, the Company initiated cost reduction initiatives that included minimizing drilling activities until margins improved as a result of (i) commodity price increases and/or (ii) well cost reductions. Associated therewith, the Company significantly curtailed development expenditures during the first nine months of 2009. As a result of the successes realized from the aforementioned cost reduction initiatives and increases in 2009 oil prices, the Company implemented a plan to resume oil- and liquids-rich-gas-focused drilling activities during 2010 and has targeted its 2010 capital budget at $800 million to $900 million, excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs. The Company s proved undeveloped well locations as of December 31, 2009 include 1,675 well locations that have remained undeveloped for five years or more. Approximately 93 percent of the Company s proved undeveloped well locations that have remained undeveloped for five years or more are comprised of locations in the Spraberry field of West Texas in the Permian Basin. The Company recorded four proved undeveloped well locations and 2 MMBOE of proved undeveloped reserves in the United States under the reliable technology and reasonable certainty provisions of the Reserve Ruling, which would not have been recorded under the rules existing prior to the Reserve Ruling.

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The following table represents the estimated timing and cash flows of developing the Company s proved undeveloped reserves as of December 31, 2009 (dollars in thousands):

| Year Ended December 31, (a) | Estimated Future Production (MBOE) | Future Cash Inflows | Future Production Costs | Future Development Costs | Future Net Cash Flows |
|---|---|---|---|---|---|
| 2010 | 1,874 | $ 88,586 | $ 19,008 | $ 293,305 | $ (223,727) |
| 2011 | 6,693 | 280,931 | 53,081 | 619,957 | (392,107) |
| 2012 | 12,705 | 500,917 | 94,827 | 902,030 | (495,940) |
| 2013 | 18,289 | 721,328 | 136,294 | 1,052,605 | (467,571) |
| 2014 | 24,025 | 958,942 | 178,621 | 1,171,222 | (390,901) |
| Thereafter | 311,151 | 12,005,180 | 3,935,060 | 194,532 | 7,875,588 |
| | 374,737 | $ 14,555,884 | $ 4,416,891 | $ 4,233,651 | $ 5,905,342 |

(a) Beginning in 2010 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling.

**Description of Properties**

***United States***

Approximately 88 percent of the Company s proved reserves at December 31, 2009 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 and the Spraberry and Raton fields have a large portfolio of low-risk drilling opportunities. The cash flows generated from these fields provide funding for the Company s other development and exploration activities both domestically and internationally.

The following tables summarize the Company s United States development and exploration/extension drilling activities during 2009:

| | Development Drilling | | | | |
|---|---|---|---|---|---|
| | Beginning Wells In Progress | Wells Spud | Successful Wells | Unsuccessful Wells | Ending Wells In Progress |
| Permian Basin | 3 | 55 | 48 | | 10 |
| Rocky Mountains | 2 | 7 | 9 | | |
| Alaska | 2 | 2 | 3 | | 1 |
| Total United States | 7 | 64 | 60 | | 11 |

| | Exploration/Extension Drilling | | | | |
|---|---|---|---|---|---|
| | Beginning Wells In Progress | Wells Spud | Successful Wells | Unsuccessful Wells | Ending Wells In Progress |
| Rocky Mountains | 4 | 1 | 3 | 1 | 1 |
| Onshore Gulf Coast | 3 | 4 | 3 | 1 | 3 |
| Barnett Shale | 2 | 7 | 7 | | 2 |
| Alaska | 1 | 1 | | | 2 |
| Total United States | 10 | 13 | 13 | 2 | 8 |

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The following table summarizes the Company s United States costs incurred by geographic area during 2009:

| | Property Acquisition Costs Proved | Property Acquisition Costs Unproved | Exploration Costs | Development Costs | Asset Retirement Obligations | Total |
|---|---|---|---|---|---|---|
| | | | (in thousands) | | | |
| Permian Basin | $ 4,002 | $ 7,110 | $ 8,981 | $ 107,231 | $ (1,288) | $ 126,036 |
| Mid-Continent | | | 451 | 5,626 | (1,417) | 4,660 |
| Rocky Mountains | 83 | 1,406 | 13,647 | 22,941 | 22,506 | 60,583 |
| Gulf of Mexico | | | 397 | (36) | 20 | 381 |
| Onshore Gulf Coast | 4,309 | 61,904 | 35,179 | 1,775 | (296) | 102,871 |
| Barnett Shale | 376 | 10,015 | 15,975 | 563 | (246) | 26,683 |
| Alaska | | (347) | 14,876 | 98,379 (a) | 1,011 | 113,919 |
| Total United States | $ 8,770 | $ 80,088 | $ 89,506 | $ 236,479 | $ 20,290 | $ 435,133 |

(a) Includes $9.7 million of capitalized interest related to the Oooguruk 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 three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. In addition, the Company continues to complete the majority of its wells in the Wolfcamp formation, at depths ranging from 9,200 feet to 11,300 feet with successful 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, and the ability to contain operating expenses and drilling costs through economies of scale.

During 2008, the Company initiated a program to test 20-acre infill drilling performance, as part of its announced recovery improvement initiatives. The Company drilled and completed eleven 20-acre wells in 2008 and completed nine additional 20-acre wells in 2009 with encouraging results.

During 2010, the Company is commencing a Spraberry field waterflood project that is located on approximately 7,000 acres within an existing Spraberry unit. Drilling, conversion and facility work should be completed during the first half of 2010 with water injection commencing during the second half of 2010.

The 20-acre well spacing and waterflood initiatives described above are being implemented to increase the Spraberry field recovery percentage in those areas of the field that are expected to be conducive for these undertakings. However, the ultimate incremental recovery rates associated with these initiatives cannot be precisely predicted at this time.

During 2009, the Company drilled 48 wells in the Spraberry field and acquired approximately 32,000 gross acres, bringing its total acreage position to approximately 884,000 gross acres (755,000 net acres). In support of the cost reduction initiatives implemented during 2008, the majority of the Company s 2009 drilling program was limited to wells necessary to hold acreage. As a result of successes realized from the Company s cost reduction initiatives and rising oil prices during the first half of 2009, the Company began increasing its rig count and drilling expenditures during the fourth quarter of 2009, with 12 rigs running in the Spraberry field at the end of the year. The Company plans to increase its rig count throughout 2010, with approximately 425 wells planned for the year. The Company intends to continue to expand its drilling program past 2010, with plans to increase its rig count to 40 rigs by 2012, during which the Company expects to drill approximately 1,000 wells per year. The Company plans to acquire Company-owned rigs to support about 25 percent of the planned 40-rig program.

**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 gas in the Hugoton field has an average energy content of 1,025 Btu. The Company s Hugoton properties are located on approximately 285,000 gross acres (247,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, approximately 990 of which it operates, and partial royalty interests in approximately 220 wells. The Company owns substantially all of the gathering and processing facilities, primarily through the Satanta plant, which processes its production from the Hugoton field. This ownership allows the Company to control the production, gathering, processing and sale of its Hugoton field gas and NGL production.

The Company s Hugoton operated wells are capable of producing approximately 65 MMcf of wet gas per day (i.e., gas production at the wellhead before processing or field fuel use and before reduction for royalties). Pioneer successfully led a cooperative effort with other operators in this field to effect rule changes which will enable further field development in future years. As part of the rule changes, the state-regulated production allowables were canceled as of December 31, 2007, and the Company received regulatory approval to commingle production from the Panoma and Council Grove formations. A commingling program was initiated in 2008 with positive results and the Company is evaluating expanding this project further. To capitalize on these rule changes, future completion designs have been developed along with an optimization plan for the existing field compression system.

*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 in the West Panhandle field has an average energy content of 1,365 Btu and is produced from approximately 675 wells on more than 250,000 gross acres (240,000 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.

**Rocky Mountains**

The Raton Basin properties are located in the southeast portion of Colorado. Exploration for CBM in the Raton Basin began in the late 1970s and continued through the late 1980s, with several companies drilling and testing more than 100 wells during this period. The absence of a pipeline to transport gas from the Raton Basin prevented full scale development until January 1995, when Colorado Interstate Gas Company completed the construction of the Picketwire lateral pipeline system (the Picketwire Lateral ). Since the completion of the Picketwire Lateral, production has continued to grow, resulting in expansion of the system s capacity by its operator, the most recent expansion of which was in 2005. The Company owns approximately 318,000 gross acres (231,000 net acres) in the center of the Raton Basin with current production from coal seams in the Vermejo and Raton formations. The Company s gas in the Raton Basin has an average energy content of 1,003 Btu. 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. In the Raton field, the Company sells its gas at a Mid-Continent index price, which generally provides higher realized gas prices as compared to the Rockies-based indexes. During December 2009, the Company entered into a ten-year firm transportation contract that commences upon completion of a new 675-mile pipeline spanning from Opal, Wyoming to Malin, Oregon. Upon completion of the pipeline s construction, which is currently anticipated during the first quarter of 2011, the Company will have 75,000 MMBtu per day of throughput capacity under this agreement.

The Company s Raton Basin production volumes averaged 31,046 BOEPD for 2009. Production for 2009 experienced a 6 percent decline as compared to 2008 production. The Company continues to realize the benefits of its cost reduction initiatives in the Raton Basin, decreasing total production costs by 17 percent, as compared to 2008, contributing to a reduction of production costs (excluding production and ad valorem taxes) per BOE to $9.42 for 2009, as compared to $10.71 per BOE for 2008. The Company has been able to maintain relatively stable production, with low rates of decline, through initiatives such as compressor upgrades and optimization of compressor configurations.

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The production decline for 2009, as compared to 2008, is due to the small capital investment in the field for 2009. The Company drilled seven development wells in the Raton CBM field in 2009 and completed projects to enhance its gathering and compression facilities in the area.

**Onshore Gulf Coast**

Drilling in the South Texas area in 2009 was sharply curtailed in support of the Company s cost reduction initiatives. The 2009 drilling activity was primarily focused on delineating the Eagle Ford Shale formation within the Company s existing 310,000 gross acre lease position. Production volumes averaged 12,016 BOEPD in 2009, representing a 5 percent decline from 2008 daily production.

A total of three wells were completed during 2009 in the onshore Gulf Coast area of operations. One Eagle Ford Shale exploration well, the Frederich Gas Unit No. 1, was spud in 2008 and completed as a discovery and brought on production during 2009. Another Eagle Ford Shale well, the Sinor Ranch No. 5, was completed as a discovery during 2009. Additionally, two Eagle Ford wells began drilling and remained in progress on December 31, 2009. The Crawley Gas Unit No.1 was completed as a discovery in early January 2010 and an additional Eagle Ford Shale well was in progress as of December 31, 2009 and is expected to be completed during the first quarter of 2010.

Over 2,000 square miles of 3-D seismic data originally acquired to assess Edwards formation drilling opportunities has been used for identifying and prioritizing Eagle Ford Shale well locations. In addition, the 3-D seismic coverage is being used to generate prioritized Edwards formation drilling. Numerous Edwards formation development well locations remain to be drilled in the previously discovered Moray, Sawfish, Skipjack and Amberjack fields. In addition there are several as yet undrilled exploration prospects. The Company continues to maintain a strong leasehold position in South Texas through lease renewals and acquisitions.

The Company has announced plans to seek a joint venture partner for all or a portion of its Eagle Ford Shale acreage position. The Company expects to receive bids from potential joint venture partners during the second quarter of 2010 and close a transaction by mid-year. There can be no assurance that a joint venture transaction can be consummated on terms acceptable to the Company.

**Barnett Shale**

During 2009, the Company s production volumes averaged 3,002 BOEPD, representing a 24 percent increase over 2008 daily production. The Company participated in the drilling of four successful exploration and development wells on non-operated properties. Another three non-operated wells were drilled, but were not completed as of December 31, 2009. During 2009, the Company enhanced its Barnett Shale acreage position through leasing and acquisitions and acquired approximately 130 square miles of 3-D seismic data. During 2009, the Company focused on improving operational efficiencies, including completing several compressor and artificial lift optimization projects, completing well workovers and enhancing the capacity of water disposal systems.

The Company s total lease holdings in the Barnett Shale play now approximate 65,000 gross acres, most of which is supported by 3-D seismic data.

**Alaska**

*Oooguruk.* In 2002, the Company acquired a 70 percent working interest and operatorship in ten state leases on Alaska s North Slope, and in 2003 drilled three exploratory wells to test a possible extension of the productive sands in the Kuparuk River field in the shallow waters offshore the North Slope of Alaska. Although all three of the wells found the sands filled with oil, they were too thin to be considered commercial on a stand-alone basis. However, the wells also encountered thick sections of oil-bearing Jurassic-aged sands, and the first well flowed at a rate of approximately 1,300 Bbls per day. In January 2004, the Company farmed-into a large acreage block to the southwest of the Company s discovery. In 2004, Pioneer completed an extensive technical and economic evaluation of the resource potential within this area. As a result of this evaluation, the Company performed front-end engineering and permitting activities during 2005 to further define the scope of the project. In early 2006, the Company announced that it had approved the development of the Oooguruk field in the project area.

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The Company constructed and armored a gravel drilling and production island site in 2006. Installation of a subsea flowline and production facilities to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit was completed in 2007. Pioneer assembled the drilling rig on location and commenced drilling the first of an estimated 33 horizontal development and injector wells in December of 2007. During 2008, the Company completed two producing wells, one injection well and one disposal well. The Company commenced production from the Oooguruk development project during the second quarter of 2008. During 2009, development and extension drilling progressed and net production averaged approximately 4,600 Bbls per day for the year. Development drilling is expected to continue throughout 2010 and beyond.

*Cosmopolitan.* In 2005, the Company acquired an interest in the Cosmopolitan Unit in the Cook Inlet of Alaska. Through a series of transactions, the Company now owns 100 percent of the Cosmopolitan Unit. The previous operator of the Cosmopolitan Unit had an oil discovery for which economic viability was not determined. During 2005 and 2006, the Company completed and interpreted a 3-D seismic shoot. During 2007, the Company drilled the Hansen #1A L1 well, a lateral sidetrack from an existing wellbore, to appraise the resource potential of the unit. The initial unstimulated production test results were encouraging and additional permitting and facilities planning ensued during 2008 to further evaluate the unit s resource potential. During 2009, the Company progressed engineering studies and commenced a workover of the Hansen #1A-L1 well. During 2010, the Company plans to complete the Hansen #1A-L1 workover, fracture stimulate the well, flow test the well, evaluate the production flow rate information from the fractured well test, progress project permitting and develop plans for a second well to further delineate the extent of the unit s resource potential.

***International***

The Company s international operations are located offshore South Africa and onshore in southern Tunisia.

The following tables summarize the Company s Tunisia exploration/extension and development drilling activities during 2009:

| | Beginning Wells In Progress | Wells Spud | Successful Wells | Unsuccessful Wells | Ending Wells In Progress |
|---|---|---|---|---|---|
| Exploration/extension drilling | 5 | 2 | | 2 | 5 |
| Development drilling | | 1 | 1 | | |
| Total | 5 | 3 | 1 | 2 | 5 |

The following table summarizes the Company s international costs incurred by geographic area during 2009:

| | Property Acquisition Costs Proved | Property Acquisition Costs Unproved | Exploration Costs | Development Costs | Asset Retirement Obligations | Total |
|---|---|---|---|---|---|---|
| | | | (in thousands) | | | |
| South Africa | $ 65 | $ | $ 623 | $ (1,768) | $ 320 | $ (760) |
| Tunisia | | | 20,092 | 16,991 | 318 | 37,401 |
| Other | | | 724 | | | 724 |
| Total International | $ 65 | $ | $ 21,439 | $ 15,223 | $ 638 | $ 37,365 |

**South Africa**

The Company has agreements to explore for oil and gas covering over 3.6 million acres offshore the southern coast of South Africa in water depths generally less than 650 feet.

The Sable oil field began producing in August 2003 and was shut in at the end of the third quarter of 2008. Over its five-year life, the Sable oil field performed better than expected, recovering approximately 23.6 million gross barrels of oil. During the life of the Sable oil field, the majority of the gas produced in conjunction with the oil

production was injected back into the reservoir. The Company had a 40 percent working interest in the oil production from the Sable field.

In 2005, the Company sanctioned the non-operated South Coast Gas development project, which included a subsea tie-back of gas from the Sable field and five additional gas accumulations to an existing production facility on the F-A platform for transportation via existing pipelines to a gas-to-liquids plant. Pioneer has a 45 percent working interest in the project. As part of sanctioning of the South Coast Gas project, the Company signed a six-year contract for the sale of its gas and condensate production from the project. The contract contains an obligation for the purchaser to take or pay for a total of 91.4 Bcf and associated condensate if the anticipated deliverability estimates are achieved. The price for both gas and condensate is indexed to Brent oil prices. First production from the South Coast Gas project was achieved in the third quarter of 2007.

A significant portion of the gas reserves associated with the South Coast Gas project are in the Sable field. In the third quarter of 2008, Sable oil production was shut in and operations to convert Sable s gas injection well to a producing well commenced. Gas sales from the Sable gas well were initiated in mid-October 2008 and the other South Coast Gas wells resumed production in late-October. The Sable gas well is the most productive well in the South Coast Gas project.

**Tunisia**

The Company holds interests in four separate onshore permits located in the southern portion of Tunisia. These permits cover a gross area of approximately 12,740 square kilometers containing two production concessions targeting the Acacus formation with additional future upside exploration potential from this and other formations.

*Jenein Nord Permit and Cherouq Concession.* The Jenein Nord Permit covers approximately 1,240 square kilometers. Since 2004, the Company has conducted seismic data acquisition and exploration drilling over the area. As a result of a seismic data acquisition and exploration drilling program, the Company has achieved a significant number of hydrocarbon discoveries. Based on the success, the Company, along with the government oil agency, Enterprise Tunisienne d Activities Petrolieres ( ETAP ), submitted a joint application on November 10, 2007 to the Directeur Général de l Energie for the development of a portion of the permit area called the Cherouq Concession.

On December 17, 2007, the Consultative Committee of Hydrocarbons, the advisory committee to the Directeur Général de l Energie, approved the Cherouq Concession, resulting in the Company and ETAP each holding a 50 percent working interest in the concession. The concession covers approximately 760 square kilometers of the Jenein Nord Permit. Since the second half of 2006, the Company has drilled fourteen wells in the concession, with first production being achieved in late 2007. As of December 2009, gross production from the Cherouq Concession has been approximately 5.9 million barrels.

The Company plans to install an artificial lift system and commence drilling operations in the first half of 2010. The Company had one exploratory well suspended and classified as in progress as of December 31, 2009 on the Jenein Nord permit.

*Borj El Khadra Permit and Adam Concession.* The Borj El Khadra Permit, including the Adam Concession, covers approximately 3,725 square kilometers. Production from the Adam Concession began in May 2003, for which the Company has a 20 percent and 40 percent working interest on exploitation and exploration activities, respectively. During 2009, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling three wells, of which one was a successful Adam concession development well and two were unsuccessful Borj El Khadra Permit exploratory wells.

The Company plans to drill up to three additional wells in the Adam Concession during 2010. On the Borj El Khadra Permit the Company intends to acquire an additional 850 square kilometers of 3-D seismic data and drill an exploration well. The Company had two Borj El Khadra Permit exploratory wells and one Adam concession extension well suspended and classified as in progress as of December 31, 2009.

*El Hamra Permit.* The El Hamra exploration permit covers approximately 4,000 square kilometers, of which the Company is operator with a 50 percent working interest during the exploration period. During 2010, the Company plans to further interpret the seismic data in order to develop existing geological prospects.

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*Anaguid Permit.* The Anaguid exploration permit covers approximately 3,800 square kilometers. In 2007, the Company acquired an additional 15 percent interest in the Anaguid exploration permit, thereby increasing its interest to 60 percent (during the exploration period) and resulting in the transfer of operations to Pioneer. During 2009, the Company prepared a plan of development to request approval to convert a portion of the existing exploration permit into a production concession. The Company plans to drill up to two additional Anaguid exploration wells during 2010 and had one exploratory well suspended and classified as in progress as of December 31, 2009.

**Selected Oil and Gas Information**

The following tables set forth selected oil and gas information from continuing operations for the Company as of and for each of the years ended December 31, 2009, 2008 and 2007. 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.

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***Production, price and cost data.*** The following tables set forth production, price and cost data with respect to the Company s properties for 2009, 2008 and 2007. These amounts represent the Company s historical results from continuing operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not agree to the reserve volume tables in the Unaudited Supplementary Information section included in Item 8. Financial Statements and Supplementary Data due to field fuel volumes and production from discontinued operations being included in the reserve volume tables.

**PRODUCTION, PRICE AND COST DATA**

| | Year Ended December 31, 2009 | | | | | |
|---|---|---|---|---|---|---|
| | United States | | | South Africa | Tunisia | Total |
| | Spraberry Field (a) | Raton Field (a) | Total | | | |
| **Production information:** | | | | | | |
| **Annual sales volumes:** | | | | | | |
| Oil (MBbls) | 5,836 | | 9,113 | 137 | 2,384 | 11,634 |
| NGLs (MBbls) | 3,454 | | 7,183 | | | 7,183 |
| Gas (MMcf) | 15,313 | 67,991 | 128,753 | 9,321 | 609 | 138,683 |
| Total (MBOE) | 11,842 | 11,332 | 37,756 | 1,690 | 2,485 | 41,931 |
| **Average daily sales volumes:** | | | | | | |
| Oil (Bbls) | 15,989 | | 24,968 | 375 | 6,531 | 31,874 |
| NGLs (Bbls) | 9,461 | | 19,680 | | | 19,680 |
| Gas (Mcf) | 41,954 | 186,278 | 352,749 | 25,538 | 1,668 | 379,955 |
| Total (BOE) | 32,443 | 31,046 | 103,440 | 4,631 | 6,809 | 114,880 |
| **Average prices, including hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 73.12 | $ | $ 75.60 | $ 65.94 | $ 60.98 | $ 72.49 |
| NGL (per Bbl) | $ 25.91 | $ | $ 29.76 | $ | $ | $ 29.76 |
| Gas (per Mcf) | $ 2.84 | $ 3.26 | $ 3.88 | $ 5.17 | $ 8.14 | $ 3.99 |
| Revenue (per BOE) | $ 47.27 | $ 19.59 | $ 37.15 | $ 33.85 | $ 60.49 | $ 38.40 |
| **Average prices, excluding hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 56.25 | $ | $ 55.04 | $ 65.94 | $ 60.98 | $ 56.38 |
| NGL (per Bbl) | $ 25.91 | $ | $ 28.45 | $ | $ | $ 28.45 |
| Gas (per Mcf) | $ 2.84 | $ 3.26 | $ 3.32 | $ 5.17 | $ 8.14 | $ 3.47 |
| Revenue (per BOE) | $ 38.96 | $ 19.59 | $ 30.02 | $ 33.85 | $ 60.49 | $ 31.98 |
| **Average costs (per BOE):** | | | | | | |
| **Production costs:** | | | | | | |
| Lease operating | $ 10.47 | $ 5.14 | $ 7.39 | $ 3.26 | $ 7.38 | $ 7.22 |
| Third-party transportation charges | | 2.39 | 0.95 | | 1.69 | 0.96 |
| Net natural gas plant/gathering | (1.23) | 1.79 | 0.27 | | | 0.25 |
| Workover | 1.30 | 0.10 | 0.55 | | 2.58 | 0.65 |
| Total | $ 10.54 | $ 9.42 | $ 9.16 | $ 3.26 | $ 11.65 | $ 9.08 |
| **Production and ad valorem taxes:** | | | | | | |
| Ad valorem | $ 2.10 | $ 0.39 | $ 1.51 | $ | $ | $ 1.36 |
| Production | 2.72 | 0.12 | 1.10 | | | 0.99 |
| Total | $ 4.82 | $ 0.51 | $ 2.61 | $ | $ | $ 2.35 |
| **Depletion expense** | $ 8.69 | $ 18.19 | $ 14.20 | $ 38.33 | $ 8.77 | $ 14.85 |

(a) The Company does not record the results of its hedging activities at a field level.

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**PRODUCTION, PRICE AND COST DATA - (Continued)**

| | Year Ended December 31, 2008 | | | | | |
|---|---|---|---|---|---|---|
| | United States | | | South Africa | Tunisia | Total |
| | Spraberry Field (a) | Raton Field (a) | Total | | | |
| **Production information:** | | | | | | |
| **Annual sales volumes:** | | | | | | |
| Oil (MBbls) | 5,713 | | 7,720 | 880 | 2,261 | 10,861 |
| NGLs (MBbls) | 2,981 | | 6,971 | | | 6,971 |
| Gas (MMcf) | 14,069 | 72,386 | 134,248 | 3,745 | 866 | 138,859 |
| Total (MBOE) | 11,038 | 12,064 | 37,065 | 1,504 | 2,406 | 40,975 |
| **Average daily sales volumes:** | | | | | | |
| Oil (Bbls) | 15,612 | | 21,091 | 2,405 | 6,178 | 29,674 |
| NGLs (Bbls) | 8,141 | | 19,048 | | | 19,048 |
| Gas (Mcf) | 38,440 | 197,775 | 366,796 | 10,232 | 2,367 | 379,395 |
| Total (BOE) | 30,161 | 32,963 | 101,271 | 4,110 | 6,573 | 111,954 |
| **Average prices, including hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 117.10 | $ | $ 65.74 | $ 110.21 | $ 90.64 | $ 74.53 |
| NGL (per Bbl) | $ 46.49 | $ | $ 51.31 | $ | $ | $ 51.31 |
| Gas (per Mcf) | $ 6.33 | $ 7.16 | $ 7.66 | $ 5.83 | $ 12.04 | $ 7.64 |
| Revenue (per BOE) | $ 81.24 | $ 42.95 | $ 51.08 | $ 79.00 | $ 89.53 | $ 54.36 |
| **Average prices, excluding hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 98.88 | $ | $ 95.82 | $ 110.21 | $ 90.64 | $ 95.91 |
| NGL (per Bbl) | $ 46.49 | $ | $ 51.56 | $ | $ | $ 51.56 |
| Gas (per Mcf) | $ 6.33 | $ 7.16 | $ 7.39 | $ 5.83 | $ 12.04 | $ 7.37 |
| Revenue (per BOE) | $ 71.81 | $ 42.95 | $ 56.41 | $ 79.00 | $ 89.53 | $ 59.18 |
| **Average costs (per BOE):** | | | | | | |
| **Production costs:** | | | | | | |
| Lease operating | $ 12.57 | $ 5.16 | $ 7.66 | $ 25.98 | $ 6.26 | $ 8.26 |
| Third-party transportation charges | | 2.56 | 1.06 | | 1.93 | 1.07 |
| Net natural gas plant/gathering | (2.73) | 2.90 | 0.16 | | | 0.15 |
| Workover | 2.61 | 0.09 | 0.93 | | | 0.84 |
| Total | $ 12.45 | $ 10.71 | $ 9.81 | $ 25.98 | $ 8.19 | $ 10.32 |
| **Production and ad valorem taxes:** | | | | | | |
| Ad valorem | $ 2.31 | $ 0.81 | $ 1.58 | $ | $ | $ 1.43 |
| Production | 5.05 | 1.11 | 2.86 | | | 2.58 |
| Total | $ 7.36 | $ 1.92 | $ 4.44 | $ | $ | $ 4.01 |
| **Depletion expense** | $ 7.61 | $ 12.90 | $ 11.30 | $ 18.37 | $ 5.96 | $ 11.25 |

(a) The Company does not record the results of its hedging activities at a field level.

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**PRODUCTION, PRICE AND COST DATA - (Continued)**

| | Year Ended December 31, 2007 | | | | | |
|---|---|---|---|---|---|---|
| | United States | | | South Africa | Tunisia | Total |
| | Spraberry Field (a) | Raton Field (a) | Total | | | |
| **Production information:** | | | | | | |
| **Annual sales volumes:** | | | | | | |
| Oil (MBbls) | 4,571 | | 6,374 | 979 | 1,403 | 8,756 |
| NGLs (MBbls) | 3,174 | | 6,760 | | | 6,760 |
| Gas (MMcf) | 11,783 | 62,083 | 113,447 | 1,037 | 917 | 115,401 |
| Total (MBOE) | 9,709 | 10,347 | 32,041 | 1,151 | 1,557 | 34,749 |
| **Average daily sales volumes:** | | | | | | |
| Oil (Bbls) | 12,523 | | 17,462 | 2,681 | 3,845 | 23,988 |
| NGLs (Bbls) | 8,697 | | 18,520 | | | 18,520 |
| Gas (Mcf) | 32,282 | 170,091 | 310,815 | 2,840 | 2,513 | 316,168 |
| Total (BOE) | 26,600 | 28,349 | 87,785 | 3,154 | 4,264 | 95,203 |
| **Average prices, including hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 95.72 | $ | $ 63.25 | $ 76.36 | $ 70.04 | $ 65.80 |
| NGL (per Bbl) | $ 38.33 | $ | $ 41.59 | $ | $ | $ 41.59 |
| Gas (per Mcf) | $ 6.00 | $ 6.06 | $ 7.25 | $ 6.76 | $ 8.77 | $ 7.26 |
| Revenue (per BOE) | $ 64.88 | $ 36.34 | $ 47.04 | $ 70.98 | $ 68.33 | $ 48.79 |
| **Average prices, excluding hedge results and amortization of deferred VPP revenue:** | | | | | | |
| Oil (per Bbl) | $ 71.73 | $ | $ 70.16 | $ 76.72 | $ 70.04 | $ 70.88 |
| NGL (per Bbl) | $ 38.33 | $ | $ 41.59 | $ | $ | $ 41.59 |
| Gas (per Mcf) | $ 4.89 | $ 6.06 | $ 6.00 | $ 6.76 | $ 8.77 | $ 6.03 |
| Revenue (per BOE) | $ 52.23 | $ 36.34 | $ 43.98 | $ 71.29 | $ 68.33 | $ 45.97 |
| **Average costs (per BOE):** | | | | | | |
| **Production costs:** | | | | | | |
| Lease operating | $ 10.35 | $ 4.49 | $ 6.31 | $ 22.43 | $ 3.46 | $ 6.71 |
| Third-party transportation charges | | 2.53 | 1.00 | | 1.57 | 0.99 |
| Net natural gas plant/gathering | (2.53) | 2.04 | 0.16 | | | 0.16 |
| Workover | 1.62 | 0.18 | 0.75 | | 0.11 | 0.69 |
| Total | $ 9.44 | $ 9.24 | $ 8.22 | $ 22.43 | $ 5.14 | $ 8.55 |
| **Production and ad valorem taxes:** | | | | | | |
| Ad valorem | $ 2.06 | $ 0.55 | $ 1.36 | $ | $ | $ 1.25 |
| Production | 4.02 | 0.69 | 2.16 | | | 2.00 |
| Total | $ 6.08 | $ 1.24 | $ 3.52 | $ | $ | $ 3.25 |
| **Depletion expense** | $ 5.80 | $ 12.46 | $ 10.08 | $ 12.07 | $ 5.01 | $ 9.92 |

(a) The Company does not record the results of its hedging activities at a field level.

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***Productive wells.*** The following table sets forth the number of productive oil and gas wells attributable to the Company s properties as of December 31, 2009, 2008 and 2007:

**PRODUCTIVE WELLS (a)**

| | Gross Productive Wells | | | Net Productive Wells | | |
|---|---|---|---|---|---|---|
| | Oil | Gas | Total | Oil | Gas | Total |
| **As of December 31, 2009:** | | | | | | |
| United States | 5,332 | 5,021 | 10,353 | 4,566 | 4,604 | 9,170 |
| South Africa | | 6 | 6 | | 3 | 3 |
| Tunisia | 29 | | 29 | 9 | | 9 |
| Total | 5,361 | 5,027 | 10,388 | 4,575 | 4,607 | 9,182 |
| **As of December 31, 2008:** | | | | | | |
| United States | 5,374 | 4,988 | 10,362 | 4,561 | 4,685 | 9,246 |
| South Africa | | 6 | 6 | | 3 | 3 |
| Tunisia | 28 | | 28 | 8 | | 8 |
| Total | 5,402 | 4,994 | 10,396 | 4,569 | 4,688 | 9,257 |
| **As of December 31, 2007:** | | | | | | |
| United States | 5,134 | 4,774 | 9,908 | 4,255 | 4,477 | 8,732 |
| South Africa | 3 | 5 | 8 | 1 | 2 | 3 |
| Tunisia | 13 | | 13 | 3 | | 3 |
| Total | 5,150 | 4,779 | 9,929 | 4,259 | 4,479 | 8,738 |

(a) Productive wells consist of producing wells and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. If any well in which one of the multiple completions is an oil completion, then the well is classified as an oil well. As of December 31, 2009, the Company owned interests in three gross wells containing multiple completions.

***Leasehold acreage.*** The following table sets forth information about the Company s developed, undeveloped and royalty leasehold acreage as of December 31, 2009:

**LEASEHOLD ACREAGE**

| | Developed Acreage | | Undeveloped Acreage | | Royalty |
|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Acreage |
| United States: | | | | | |
| Onshore | 1,478,019 | 1,266,583 | 1,179,195 | 900,350 | 304,442 |
| Offshore | 5,760 | 2,880 | | | 5,000 |
| | 1,483,779 | 1,269,463 | 1,179,195 | 900,350 | 309,442 |
| South Africa | 119,579 | 53,281 | 3,508,421 | 1,578,790 | |
| Tunisia | 287,540 | 80,044 | 2,860,487 | 1,569,116 | |
| Total | 1,890,898 | 1,402,788 | 7,548,103 | 4,048,256 | 309,442 |

The following table sets forth the expiration dates of the leases on the Company s gross and net undeveloped acres as of December 31, 2009:

| | Acres Expiring (a) | |
|---|---|---|
| | Gross | Net |
| 2010 (b) | 1,470,699 | 885,046 |
| 2011 | 991,447 | 494,775 |
| 2012 | 259,037 | 229,693 |
| 2013 | 164,247 | 146,539 |
| 2014 | 65,557 | 57,177 |
| Thereafter | 4,597,116 | 2,235,026 |
| Total | 7,548,103 | 4,048,256 |

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

(b) All acres subject to expiration during 2010 are in North America and Tunisia. The Company may extend the leases prior to their expiration based upon 2010 planned activities or for other business reasons. In certain leases, the extension is only subject to the Company s election to extend and the fulfillment of certain capital expenditures commitments. In other cases, the extensions are subject to the consent of third parties, and no assurance can be given that the requested extensions will be granted. See Description of Properties above for information regarding the Company s drilling operations.

***Drilling activities.*** The following table sets forth the number of gross and net productive and dry hole wells in which the Company had an interest that were drilled during 2009, 2008 and 2007. 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.

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**DRILLING ACTIVITIES**

| | Gross Wells Year Ended December 31, | | | Net Wells Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2007 | 2009 | 2008 | 2007 |
| **United States:** | | | | | | |
| Productive wells: | | | | | | |
| Development | 60 | 526 | 602 | 58 | 504 | 581 |
| Exploratory | 13 | 56 | 41 | 7 | 46 | 33 |
| Dry holes: | | | | | | |
| Development | | 7 | 2 | | 7 | 2 |
| Exploratory | 2 | 17 | 5 | 2 | 9 | 3 |
| | 75 | 606 | 650 | 67 | 566 | 619 |
| **Canada:** | | | | | | |
| Productive wells: | | | | | | |
| Development | | | 1 | | | 1 |
| Exploratory | | | 7 | | | 5 |
| Dry holes: | | | | | | |
| Development | | | 1 | | | |
| Exploratory | | | 6 | | | 5 |
| | | | 15 | | | 11 |
| **South Africa:** | | | | | | |
| Productive wells: | | | | | | |
| Development | | | 3 | | | 1 |
| Exploratory | | | | | | |
| | | | 3 | | | 1 |
| **Tunisia:** | | | | | | |
| Productive wells: | | | | | | |
| Development | 1 | | | | | |
| Exploratory | | 6 | 12 | | 3 | 8 |
| Dry holes: | | | | | | |
| Development | | | | | | |
| Exploratory | 2 | 2 | 4 | 1 | 1 | 3 |
| | 3 | 8 | 16 | 1 | 4 | 11 |
| **West Africa:** | | | | | | |
| Dry holes: | | | | | | |
| Development | | | | | | |
| Exploratory | | | 1 | | | |
| | | | 1 | | | |
| Total | 78 | 614 | 685 | 68 | 570 | 642 |
| Success ratio (a) | 95% | 96% | 97% | 96% | 97% | 98% |

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

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The following table sets forth information about the Company s wells upon which drilling was in progress as of December 31, 2009:

| | Gross Wells | Net Wells |
|---|---|---|
| **United States:** | | |
| Development | 11 | 10 |
| Exploratory | 8 | 7 |
| | 19 | 17 |
| **Tunisia:** | | |
| Exploratory | 5 | 3 |
| Total | 24 | 20 |

**Item 3. Legal Proceedings**

The Company is party to the legal proceedings that are described under Legal actions in Note I of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. The Company is also party to other 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 other 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.

**Item 4. Submission of Matters to a Vote of Security Holders**

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2009.

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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 Board declared dividends to the holders of the Company s common stock of $.08 per share and $.30 per share during the years ended December 31, 2009 and 2008, respectively.

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, 2009 and 2008:

| | High | Low | Dividends Declared Per Share |
|---|---|---|---|
| **Year ended December 31, 2009** | | | |
| Fourth quarter | $ 50.00 | $ 33.49 | $ |
| Third quarter | $ 36.74 | $ 21.78 | $ 0.04 |
| Second quarter | $ 30.56 | $ 15.67 | $ |
| First quarter | $ 20.44 | $ 11.88 | $ 0.04 |
| **Year ended December 31, 2008** | | | |
| Fourth quarter | $ 52.27 | $ 14.03 | $ |
| Third quarter | $ 82.21 | $ 46.24 | $ 0.16 |
| Second quarter | $ 82.16 | $ 48.49 | $ |
| First quarter | $ 50.00 | $ 36.37 | $ 0.14 |

On February 23, 2010, the last reported sales price of the Company s common stock, as reported in the NYSE composite transactions, was $46.18 per share.

As of February 23, 2010, the Company s common stock was held by approximately 22,000 holders of record.

**Purchases of Equity Securities by the Issuer and Affiliated Purchasers**

The following table summarizes the Company s purchases of treasury stock during the three months ended December 31, 2009:

| 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 2009 | 1,584 | $ 36.29 | | |
| November 2009 | 1,183 | $ 41.19 | | |
| December 2009 | 34 | $ 41.25 | | |
| Total | 2,801 | $ 38.42 | | $ 355,789,018 |

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

During 2007, the Board approved a share repurchase program authorizing the purchase of up to $750 million of the Company s common stock. During 2009, 2008 and 2007, the Company purchased $16.2 million, $165.2 million and $212.8 million, respectively, of common stock pursuant to the 2007 program.

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**Item 6. Selected Financial Data**

The following selected consolidated financial data as of and for each of the five years ended December 31, 2009 for the Company 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, (a) | | | | |
|---|---|---|---|---|---|
| | 2009 | 2008 | 2007 | 2006 | 2005 |
| | (in millions, except per share data) | | | | |
| **Statements of Operations Data:** | | | | | |
| Oil and gas revenues (b) | $ 1,610.0 | $ 2,227.6 | $ 1,695.3 | $ 1,391.7 | $ 1,299.2 |
| Total revenues | $ 1,711.5 | $ 2,284.8 | $ 1,785.0 | $ 1,432.8 | $ 1,380.6 |
| Total costs and expenses (c) | $ 1,892.0 | $ 1,848.8 | $ 1,450.0 | $ 1,179.1 | $ 1,075.8 |
| Income (loss) from continuing operations | $ (132.3) | $ 234.9 | $ 229.1 | $ 125.0 | $ 165.0 |
| Income (loss) from discontinued operations, net of tax (d) | $ 90.1 | $ (3.3) | $ 143.2 | $ 612.5 | $ 367.9 |
| Net income (loss) attributable to common stockholders | $ (52.1) | $ 210.0 | $ 372.7 | $ 739.7 | $ 534.6 |
| Income (loss) from continuing operations per share (e): | | | | | |
| Basic | $ (1.25) | $ 1.79 | $ 1.86 | $ 0.93 | $ 1.17 |
| Diluted | $ (1.25) | $ 1.79 | $ 1.85 | $ 0.91 | $ 1.14 |
| Net income (loss) attributable to common stockholders per share (e): | | | | | |
| Basic | $ (0.46) | $ 1.76 | $ 3.05 | $ 5.85 | $ 3.85 |
| Diluted | $ (0.46) | $ 1.76 | $ 3.04 | $ 5.75 | $ 3.76 |
| Dividends declared per share | $ 0.08 | $ 0.30 | $ 0.27 | $ 0.25 | $ 0.22 |
| **Balance Sheet Data (as of December 31):** | | | | | |
| Total assets | $ 8,867.3 | $ 9,161.8 | $ 8,617.0 | $ 7,355.4 | $ 7,329.2 |
| Long-term obligations | $ 4,653.0 | $ 4,787.2 | $ 4,568.1 | $ 3,469.4 | $ 4,069.5 |
| Total stockholders equity | $ 3,643.0 | $ 3,679.6 | $ 3,054.7 | $ 2,999.0 | $ 2,226.4 |

(a) Certain amounts for periods prior to January 1, 2009, have been reclassified to reflect the results of operations of certain assets disposed of during 2009 as discontinued operations, rather than as a component of continuing operations (see Notes B and V of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional discussion) and to conform to the current year presentation.

(b) The Company s oil and gas revenues for 2009, as compared to those of 2008, declined by $617.6 million (or 28 percent) due to declines in commodity prices, partially offset by a two percent increase in 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.

(c) On January 31, 2009, the Company discontinued hedge accounting for its derivative contracts and began using the mark-to-market ( MTM ) method of accounting for derivatives. Under the MTM method of accounting, the Company recognized $195.6 million of derivative losses, net in its total costs and expenses of 2009, including $191.5 million of noncash MTM losses. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes B and J 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.

(d) During 2009, the Company recorded $119.3 million of pretax income for the recovery of excess royalties paid on oil and gas production from its deepwater Gulf of Mexico properties during the period from January 1, 2003 through December 31, 2005, and a $17.5 million pretax gain, primarily from the sale of substantially all of its Gulf of Mexico shelf properties. The Company s Gulf of Mexico shelf and deepwater properties were sold effective July 1, 2009 and January 1, 2006, respectively. 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 Notes B and V of Notes to Consolidated Financial Statements included in Item 8 Financial Statements and Supplementary Data for more information about the Company s discontinued operations.

(e)

Income from continuing operations per share and net income attributable to common stockholders per share amounts have been restated for the January 1, 2009 adoption of FASB Staff Position EITF 03-6-1 ( FSP EITF 03-6-1 ) to exclude the earnings of participating securities in the determination of net income (loss) per share. See Notes B and Q of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional discussion about this change in GAAP.

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**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 2009 included the following highlights:

Earnings attributable to common stockholders was a net loss of $52.1 million ($.46 per diluted share), as compared to net income attributable to common stockholders of $210.0 million ($1.76 per diluted share) in 2008. The decrease in earnings attributable to common stockholders is primarily due to:

A $617.6 million pretax decline in oil and gas revenues as a result of commodity price declines, partially offset by an increase in sales volumes;

A $185.4 million pretax increase in net derivative losses, primarily due to rising oil and NGL prices since the Company s January 31, 2009 change from hedge accounting to the mark-to market ( MTM ) accounting method; and

A $161.8 million pretax increase in depreciation, depletion and amortization ( DD&A ) expense, primarily due to (i) negative price revisions resulting from lower commodity prices during 2009 as compared to 2008 and (ii) negative reserve price revisions in the fourth quarter of 2009 associated with the SEC s new reserve reporting rules; partially offset by:

A $108.3 million decrease in pretax oil and gas production costs and production and ad valorem taxes, primarily due to successes realized from the Company s cost reduction initiatives and commodity price declines, respectively;

A $93.3 million increase in after-tax income from discontinued operations, primarily due to $119.3 million of pretax income recognized for the recovery of excess deepwater Gulf of Mexico royalties paid during 2003 through 2005 and a $17.5 million pretax gain from the divestiture of substantially all of the Company s Gulf of Mexico shelf properties during 2009; and

A $76.4 million increase in pretax Alaskan Petroleum Production Tax credit dispositions.

Daily sales volumes from continuing operations increased on a per BOE basis by three percent to 115 MBOEPD during 2009, as compared to 112 MBOEPD during 2008. Approximately 1,100 BOEPD of 2009 annual production was lost due to unplanned third-party pipeline repairs in Alaska and the Mid-Continent area and to longer-than-anticipated gas-to-liquids plant maintenance shutdowns in South Africa.

Average reported oil, NGL and gas prices from continuing operations decreased during 2009 to $72.49 per Bbl, $29.76 per Bbl and $3.99 per Mcf, respectively, as compared to respective prices of $74.53 per Bbl, $51.31 per Bbl and $7.64 per Mcf during 2008.

Average oil and gas production costs and ad valorem and production taxes per BOE from continuing operations decreased during 2009 to $9.08 and $2.35, respectively, as compared to respective per BOE costs of $10.32 and $4.01 during 2008, primarily as a result of cost reduction initiatives and commodity price declines.

Net cash provided by operating activities decreased by $490.8 million to $543.1 million for 2009, as compared to $1.0 billion in 2008, primarily due to the decrease in oil and gas revenue.

Long-term debt was reduced by $138.2 million during 2009.

Pioneer Southwest issued 3.1 million common units during 2009 for net proceeds of $61.0 million. The net proceeds from the issuance of common units were used to reduce Pioneer Southwest s credit facility indebtedness.

The Company issued $450 million of 7.5% Senior Notes due 2020 during November 2009 and used the net proceeds to reduce credit facility indebtedness.

**Significant Events**

***Commodity prices.*** Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same time period, North American gas supply was increasing as a result of the rise in domestic unconventional gas production. The combination of lower energy demand due to the economic slowdown and higher North American gas supply resulted in significant declines in prices for oil, NGL and gas. While oil and NGL prices started to steadily improve beginning in the second quarter of 2009, gas prices remained volatile throughout 2009 due to high storage levels and increasing gas supply. The outlook for a

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worldwide economic recovery in 2010 remains uncertain and therefore, the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices during 2010 will continue to be volatile.

Although the Company has entered into derivative contracts on a large portion of its production volumes through 2012, 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 cash flows would be reduced for affected periods. Significant or extended price declines could also adversely affect the amount of oil, NGL and gas that the Company can produce economically. The duration, timing and magnitude of any period of lower commodity prices cannot be predicted. 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.

As of December 31, 2009, the Company had $27.4 million of cash on hand and $1.2 billion of liquidity under its credit facility that matures in 2012. As of December 31, 2009, the Company also had $331.7 million of net accounts receivable and was a party to derivative financial instruments, of which approximately $92.3 million represented assets. Management is closely monitoring the credit standings of its customers; counterparties, including its banks; derivative counterparties and purchasers of the commodities the Company produces and sells.

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes F and J, respectively of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information about the Company s credit facility and derivative contracts.

***Cost reduction initiatives.*** During the second half of 2008, the Company increased its emphasis on reducing capital spending, operating costs and administrative expenses to support its goal of delivering net cash flow from operating activities in excess of capital requirements in 2009 and to enhance and preserve financial flexibility. These initiatives included minimizing drilling activities until margins improved as a result of (i) commodity prices increasing and/or (ii) well cost reductions. As a result, the Company significantly reduced its 2009 rig activity and has realized and continues to pursue reductions in operating expenses and well costs to align costs with a lower commodity price environment. Rigs were terminated or stacked in the Spraberry, Raton, Edwards Trend and Barnett Shale areas and in Tunisia. Since the third quarter of 2008, when drilling and completion costs peaked, the Company has achieved a reduction of approximately 30 percent in the cost of drilling and completing a well in the Spraberry field. The Company s asset teams have also reduced 2009 lease operating expense per BOE from continuing operations by 13 percent during 2009, as compared to 2008. The cost savings reflect reductions in electricity, water disposal and compression rental costs and expanded use of Pioneer s internal well services in the Spraberry field.

During 2009, the Company s capital costs (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs) were $312.9 million, as compared to $1.2 billion during 2008, representing a 74 percent decrease. As a result of the successes realized from the aforementioned cost reduction initiatives and increases in 2009 oil prices, the Company implemented a plan to resume oil- and liquids-rich-gas-focused drilling activities during 2010 and has preliminarily targeted its 2010 capital budget to be in a range of $800 million to $900 million (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs).

Historically, the Company s capital and operating costs have risen during periods of increased oil, NGL and gas prices. These 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 planned.

***Sale of assets to Pioneer Southwest.*** On August 31, 2009, the Company completed a sale of oil and gas properties in the Spraberry field to Pioneer Southwest pursuant to a Purchase and Sale Agreement having an effective date of July 1, 2009. Associated therewith, Pioneer received $168.2 million of cash, including customary closing adjustments, and transferred net obligations associated with certain commodity price derivative positions and certain other liabilities to Pioneer Southwest. Proceeds were used to reduce Pioneer s credit facility indebtedness and Pioneer Southwest funded the purchase with cash on hand and borrowings under its credit facility.

***Pioneer Southwest equity offering.*** On November 16, 2009, Pioneer Southwest completed a public offering of 3,105,000 common units representing limited partner interests (the Equity Offering ). Net proceeds from the Equity Offering of $61.0 million were used to reduce Pioneer Southwest s credit facility borrowings. Following the Equity Offering, Pioneer owns a 61.9 percent limited partner interest in Pioneer Southwest.

***Senior note issuance.*** In November 2009, the Company issued $450 million of 7.5% Senior Notes due 2020 for net proceeds of $438.6 million. The net proceeds were used to reduce the Company s credit facility indebtedness.

***Modernization of oil and gas reporting.*** During 2009, the SEC issued the Reserve Ruling and the FASB issued ASU 2010-03. The Reserve Ruling and the ASU 2010-03 are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The key provisions of the Reserve Ruling and ASU 2010-03, which impact the Company s disclosures and consolidated financial statements, are as follows:

- Amending the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices;
- Adding to and amending other definitions used in estimating proved oil and gas reserves, such as reliable technology and reasonable certainty ;
- Broadening the types of technology that a reporter may use to establish reserves estimates and categories; and
- Changing disclosure requirements and providing formats for tabular reserve disclosures.

See Item 2. Properties, above Results of Operations Depletion, depreciation and amortization expense below and supplementary disclosures in Item 8 Financial Statements and Supplementary Data for associated disclosures and information about how the adoption of the Reserve Ruling and ASU 2010-03 affected the Company.

**First Quarter 2010 Outlook**

Based on current estimates, the Company expects that first quarter 2010 production will average 112,000 to 117,000 BOEPD, reflecting increased 2010 drilling activity, the expiration of the VPP obligation in the Hugoton field, the return of production in South Africa after the fourth quarter 2009 maintenance shutdown and the planned oil lifting schedule for Tunisia.

First quarter production costs from continuing operations (including production and ad valorem taxes and transportation costs) are expected to average $11.50 to $13.50 per BOE, based on current NYMEX strip prices for oil and gas. DD&A expense is expected to average $14.50 to $16.00 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $25 million to $35 million, primarily related to exploration wells, including related acreage costs, and seismic and personnel costs. General and administrative expense is expected to be $35 million to $39 million. Interest expense is expected to be $45 million to $48 million, and other expense is expected to be $12 million to $17 million. Accretion of discount on asset retirement obligations from continuing operations is expected to be $2 million to $4 million.

Noncontrolling interest in consolidated subsidiaries net income, excluding noncash MTM adjustments, is expected to be $9 million to $12 million, primarily reflecting the public ownership in Pioneer Southwest.

The Company s first quarter effective income tax rate is expected to range from 40 percent to 50 percent, based on current capital spending plans, higher tax rates in Tunisia and no significant MTM changes in the Company s derivative position. Cash income taxes are expected to be $10 million to $15 million and are primarily related to Tunisia.

**Acquisitions**

During 2009, the Company spent $88.9 million to acquire proved and unproved properties. The acquisitions primarily increased the Company s unproved acreage positions in the South Texas Eagle Ford Shale play. During 2008, the Company spent $137.6 million to acquire proved and unproved properties. The acquisitions primarily added proved reserves and increased the Company s acreage positions in the Spraberry field, Edwards Trend and Barnett Shale play. During 2007, the Company spent $536.7 million to acquire proved and unproved properties. The acquisitions primarily added proved reserves and increased the Company s acreage positions in the Spraberry field, Raton field and Barnett Shale play.

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**Divestitures**

***Mississippi and Gulf of Mexico Shelf.*** In June and August 2009, the Company sold its Mississippi and shelf properties in the Gulf of Mexico, respectively, for aggregate net proceeds of $23.6 million, resulting in a pretax gain of $17.5 million. The historical results of these assets and the related gain on disposition are reported as discontinued operations.

***Canada.*** In November 2007, the Company sold its Canadian subsidiaries for $525.7 million, resulting in a gain of $101.3 million. The historical results of these assets and the related gain on disposition are reported as discontinued operations.

**Results of Operations**

***Oil and gas revenues.*** Oil and gas revenues totaled $1.6 billion, $2.2 billion and $1.7 billion during 2009, 2008 and 2007, respectively. The revenue decrease during 2009, as compared to 2008, is reflective of decreases in the Company s revenues in all geographic areas. The decrease in 2009 oil and gas revenues relative to 2008 was due to commodity price declines during 2009 and a reduction in 2009 drilling due to cost reduction initiatives, as described above in Significant Events. In the United States, the Company s 2009 average reported NGL and gas prices declined 42 percent and 49 percent, respectively, as compared to 2008. These 2009 declines were partially offset by a 15 percent increase in the 2009 average reported oil price and a two percent increase in 2009 average daily sales volumes on a BOE basis as compared to 2008. In South Africa, the Company s average reported oil and gas prices in 2009 decreased 40 percent and 11 percent, respectively, partially offset by a 13 percent increase in average daily sales volumes on a BOE basis as compared to 2008. In Tunisia, the Company s average reported oil and gas prices in 2009 decreased 33 percent and 32 percent, respectively, partially offset by a four percent increase in average daily sales volumes on a BOE basis as compared to 2008.

The revenue increase during 2008, as compared to 2007, is reflective of increases in the Company s revenues in all geographic areas. The increase in United States revenues was primarily due to an increase in average daily sales volumes resulting from successful drilling programs, core area acquisitions and reductions in scheduled VPP deliveries, combined with a 23 percent increase in average reported NGL prices, a four percent increase in average reported oil prices and a six percent increase in average reported gas prices. South African revenues increased due to an increase in average daily sales volumes realized from a full year of sales from the portion of the wells in the South Coast Gas project that commenced gas production during the fourth quarter of 2007, and a 44 percent increase in average reported oil price, partially offset by a 14 percent decrease in average reported gas price. The increase in Tunisian revenues resulted from an increase in average daily sales volumes from successful drilling efforts, a 37 percent increase in average reported gas price and a 29 percent increase in average reported oil price.

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The following table provides average daily sales volumes from continuing operations by geographic area and in total for 2009, 2008 and 2007:

| | Year Ended December 31, |
|---|---|