PIONEER NATURAL RESOURCES CO
Form 10-K
February 25, 2009
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, 2008
	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 *(State or other jurisdiction of incorporation or organization)*	**75-2702753** *(I.R.S. Employer Identification No.)*
5205 N. O'Connor Blvd.,Suite 200, Irving, Texas *(Address of principal executive offices)*	**75039** *(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** o

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 o **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** o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). **Yes** o **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	**$ 9,166,300,086**
Number of shares of Common Stock outstanding as of February 20, 2009	**115,616,236**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held during May 2009 — Referenced in Part III of this report.

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PART III

PART IV

Cautionary Statement Concerning Forward-Looking Statements

Parts I and II of 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," "continues," "may," "will," "could," "should," "future," "potential," "esti the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company ("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 than the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations," "Item 1A. Risk Factors" 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. The Company undertakes no duty to publicly update these statements except as required by law.

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.
- *"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 per day
- *"Mont Belvieu-posted-price"* means the daily average natural gas liquids components as prices 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.
- *"proved reserves"* means the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(i)(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”; (B) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (C) crude oil, natural gas and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

- *"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 in effect at the specified date and a ten percent discount rate.
- *"VPP"* means volumetric production payment.
- *"U.S."* means United States.
- 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.

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, 2008, the Company had 1,824 employees, 1,128 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 and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. 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, 2008.

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 which, 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. During the third and fourth quarters of 2008 and continuing into the first quarter of 2009, worldwide financial markets experienced significant turmoil as a worldwide economic decline gained momentum and the availability of liquidity provided by the financial markets declined. The economic decline has significantly reduced worldwide energy consumption and demand for oil, NGLs and gas. Resulting hydrocarbon supply and demand imbalances have significantly reduced market prices for oil, NGLs and gas since the record high levels that were realized in mid-2008. Additionally, demand for drilling rigs and vessels, oilfield supplies, drill pipe and utilities reached record highs during 2008, affecting reserve finding costs and production costs. Although those costs have begun to decline, their declines have lagged significantly behind the declines in oil, NGL and gas prices, severely constricting operating margins during the second half of 2008 and resulting in negative proved reserve price revisions at the end of 2008.

For the several years preceding the 2008 worldwide economic decline, 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 during 2008 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 downturn 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 will impact 2009 commodity prices include: the impact of economic stimulus initiatives being implemented in the United States and worldwide in response to the worldwide economic decline; developments in the issues currently impacting 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, including the impact of increasing LNG deliveries to the United States.

To mitigate the impact of commodity price volatility on the Company’s net asset value, Pioneer utilizes commodity derivative contracts. 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 impact to oil and gas revenues during 2008, 2007 and 2006 from the Company’s derivative price risk management activities and the Company’s open derivative positions at December 31, 2008.

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 Edwards Trend area 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, Alaska, and the Gulf of Mexico shelf, 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, 2008, the Company’s average daily production, on a BOE basis, increased 17 percent as a result of successful drilling programs in the United States and Tunisia and a 12 percent decrease in the delivery of VPP volumes. Production, price and cost information with respect to the Company’s properties for 2008, 2007 and 2006 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, 2008, the Company drilled 1,831 gross (1,740 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 $3.1 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, 2008 include proved undeveloped reserves and proved developed reserves that are behind pipe of 246 MMBbls of oil and NGLs and 1,064 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.

As a result of the significant drop in commodity prices, the Company has implemented initiatives to reduce capital spending and operating costs in 2009 and to enhance financial flexibility. This plan includes minimizing drilling activities until margins improve as a result of (i) increased commodity prices, (ii) reduced gas price differentials relative to NYMEX quoted prices in the areas where the Company produces gas and/or (iii) decreased well costs.

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 — Drilling activities" 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 2008, 2007 and 2006, the Company invested $137.6 million, $536.7 million and $223.2 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 2008, 2007 and 2006.

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 analysis, oil and gas reserve analysis, due diligence, the submission of an indication of interest, preliminary negotiations, negotiation of a letter of intent or negotiation of a definitive agreement. The success of any acquisition is uncertain and will depend on a number of factors, some of which are outside the Company's control. See "Item 1A. Risk Factors — Acquisitions."

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, T 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 2008, 2007 and 2006.

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.

Operations by Geographic Area

The Company operates in one industry segment, that being oil and gas exploration and production. 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 price for gas or the spot price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply 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 2008, the Company’s significant purchasers of oil, NGLs and gas were Plains Marketing LP (13 percent), Enterprise Products Partners L.P. (10 percent), Occidental Energy Marketing, Inc. (9 percent) and Oneok Resources (6 percent). The Company believes that the loss of any one purchaser would not have an 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 began accounting for its derivative contracts using the mark-to-market 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 Notes J of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information concerning the impact on oil and gas revenues during 2008, 2007 and 2006 from commodity hedging activities and the Company’s open and terminated commodity derivative positions at December 31, 2008.

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.

Governmental 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 that will ensure that material information relating to the Company is made known to management and 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. Compliance with some of these regulations is costly and regulations are subject to change or reinterpretation.

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 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 (“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 crude oil or gas are currently regulated under RCRA’s non-hazardous waste provisions. However, 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 not subject to regulation under the Atomic Energy Act of 1954, or the Low Level Radioactive Waste Policy Act. 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 utilized 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 in the event of 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 activities are regulated by the Safe Drinking Water Act (the "SDWA") and analogous state and local laws. The underground injection well program under the SDWA classifies produced wastewaters and imposes restrictions on the drilling and operation of disposal wells as well as the quality of injected wastewaters. This program is designed to protect drinking water sources and requires permits from the EPA or analogous state agency for the Company's disposal wells. 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.

The waters 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, a state water court held that the use of water in CBM operations should be subject to water-use regulation under an additional agency as is the case with other uses of water in the state, including the need for the obtaining of permits, possible competition with other claimants for the use of the water and the possibility of providing mitigation water for other water users. That decision is on appeal. However, if that ruling or a similar ruling or regulation becomes applicable to the Company's CBM or other oil and gas operations, 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, 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 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.

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 implementing regulations

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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 and/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. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states (not including Texas) have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases, 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 greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which the Company conducts business could have an adverse effect on the Company's operations and demand for oil and gas.

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 impact 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, 2008. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2009. 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 impact 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. These rules are to be considered by the Colorado Legislature in its 2009 legislative session, and are expected to begin applicability in early April.

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS is currently in the process of adopting regulations that will determine whether some of the Company's facilities or operations will be subject to additional DHS-mandated security requirements. Presently, it is not possible to accurately estimate the costs the Company could incur, directly or indirectly, to comply with any such facility security laws or regulations, but such expenditures could be substantial.

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 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 impact the economics of production from these wells and/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.

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 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.

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 impacted 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 occur, they 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 and gas, market uncertainty and a variety of additional factors that are beyond our 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 impact of increasing LNG deliveries to the United States;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the impact 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 declined in 2008 from record levels in July of $145.29 per barrel to $33.87 per barrel in December, while gas prices declined from $13.58 per Mcf to $5.29 per Mcf over the same period. 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 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 impact the Company’s ability to replace its production and its future rate of growth.

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

To achieve more predictable cash flow and to reduce the Company’s exposure to adverse 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 hedged volumes,
- the counterparty to the derivative contract defaults on their 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 expose the Company to reduced revenue and liquidity when prices decline, as occurred in late 2008.

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.

To achieve more predictable cash flow and to reduce the Company's exposure to adverse 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. 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. In addition, in light of the current economic outlook, it is possible that fewer counterparties will participate in derivative transactions, which could result in a greater concentration of the Company's exposure to any one counterparty, or a larger percentage of the Company's future production could be 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;
- 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 and equipment.

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 2009. 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 several months, such decreases could be short-lived. A return to the trends of increasing demand and costs in the future may impact the Company's profitability, cash flow and ability to complete development projects as scheduled.

Future price declines could result in a reduction in the carrying value of the Company's proved oil and gas properties, which could adversely affect the Company's results of operations.

Declines in commodity prices may result in the Company having to make substantial downward adjustments to 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 2008, the Company recognized impairment charges of $104.3 million due to the impairment of the Company's net assets in the Uinta/Piceance and Mississippi areas, primarily due to declines in gas prices. 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, 2008, the Company carried unproved property costs of $204.2 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 impact 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 impact 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 crisis has affected the level of sales activity for oil and gas properties. The lack 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.

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, 2008, the Company carried goodwill of $310.6 million associated with its United States reporting unit. Goodwill is tested for impairment at least annually, requiring an estimate of the fair values of the reporting unit's assets and liabilities. Accordingly, the Company assessed its goodwill for impairment on July 1, 2008 and determined that goodwill was not impaired. However, as a result of declines in commodity prices and a significant decline in the Company's market capitalization during the second half of 2008, the Company reassessed as of December 31, 2008 whether the fair value of its net assets supported the carrying value of the Company's goodwill at its United States reporting unit. Although the Company's assessment indicated that its goodwill was not impaired as of December 31, 2008, the continuation of commodity price declines during the first quarter of 2009 provides an indication that goodwill may be at risk of future impairment. The Company will continue to assess its goodwill for impairment and such 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, 2008, the Company owned interests in four gas processing plants and thirteen treating facilities. The Company operates two of the gas processing plants and twelve 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, 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.

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.

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 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.

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, 2008 and the terms associated therewith.

The Company's ability to obtain additional financing is also impacted 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.

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. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations. 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, 2008, approximately three 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 “Critical Accounting Estimates” included in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “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.

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 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 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 prices 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 and gas; and
- changes in governmental regulations or taxation.

The Company reports all proved reserves held under production sharing arrangements and concessions utilizing the “economic interest” method, which excludes the host country’s share of proved reserves. Estimated quantities of production sharing arrangements 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. It requires the use of commodity prices, as well as operating and development costs, prevailing as of the date of computation. 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 decline rates from existing wells and the outcome of future drilling activity. Should these estimates prove inaccurate, actual production could be adversely impacted. Downturns in commodity prices could make certain drilling activities or production uneconomical, which would also adversely impact production.

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.

Recently, there has been a significant decline in the credit markets and the availability of credit, and equity values have substantially declined. 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 because of the deterioration of the credit and capital markets. This may hinder or prevent the Company from meeting its future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the repricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding. In addition, 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 generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and limited the amount of funding available to borrowers.

As a result, the Company may 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 may have a material adverse affect on the Company's results of operations.

Recently, concerns over a worldwide economic downturn, geopolitical issues, the availability and cost of credit, the U.S. 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, have precipitated a worldwide recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices, both of which have contributed to a decline in the Company's share price and corresponding market capitalization. If the economic climate in the United States or abroad continues to deteriorate, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The information included in this Report about the Company's proved reserves as of December 31, 2008, 2007 and 2006, which were located in the United States, Argentina, Canada, South Africa and Tunisia, was based on evaluations prepared by the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The reserve audits performed by NSAI in aggregate represented 87 percent, 86 percent and 89 percent of the Company's 2008, 2007 and 2006 proved reserves, respectively; and, 80 percent, 80 percent and 83 percent of the Company's 2008, 2007 and

2006 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, 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.

The Company did not provide estimates of total proved oil and gas reserves during 2008, 2007 or 2006 to any federal authority or agency, other than the SEC. The Company's reserve estimates do not include any probable or possible reserves. Also, see "Item 1A. Risk Factors" and "Critical Accounting Estimates" in "Item 7. Management's Discussion and Analysis and Results of Operations" for additional discussions regarding proved reserves and their related cash flows.

Proved Reserves

The Company's proved reserves totaled 959.6 MMBOE, 963.8 MMBOE and 904.9 MMBOE at December 31, 2008, 2007 and 2006, respectively, representing $3.2 billion, $9.0 billion and $4.7 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, 2008 (in MBOE):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
United States	(40,764)	56,751	14,263	—	(30,120)
South Africa	(1,505)	—	—	—	894
Tunisia	(2,405)	2,026	—	(652)	(2,679)
Total	(44,674)	58,777	14,263	(652)	(31,905)

Production. Production volumes include 3,129 MBOE of field fuel.

Extensions and discoveries. Extensions and discoveries are primarily comprised of discoveries in the Company's South Texas Edwards Trend, Pierre Shale additions in southeastern Colorado and extension drilling in the North Texas Barnett Shale play. The Company also recorded discoveries in Tunisia during 2008.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to acquisitions in the Company's Spraberry oil field, South Texas Edwards Trend and the North Texas Barnett Shale play.

Sales of minerals-in-place. Sales of minerals-in-place are principally related to the Tunisian government's election to participate in 50 percent of the Company's discoveries in the Cherouq concession in the Jenein Nord permit. 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 69 MMBOE of negative price revisions offset by 37 MMBOE of positive technical revisions. The Company's proved reserves at December 31, 2008 were determined using year-end NYMEX equivalent prices of $44.60 per barrel of oil and $5.71 per Mcf of gas, compared to $95.92 per barrel of oil and $6.80 per Mcf of gas at December 31, 2007.

On a BOE basis, 58 percent of the Company's total proved reserves at December 31, 2008 were proved developed reserves. Based on reserve information as of December 31, 2008, 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 21 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily sales volumes by geographic area as of and for the year ended December 31, 2008:

	Proved Reserves as of December 31, 2008				2008 Average Daily Sales Volumes		
	Oil & NGLs (MBbls)	Gas (MMcf) (a)	MBOE	Standardized Measure	Oil & NGLs (MBbls)	Gas (MMcf) (b)	BOE
	(in thousands)						
United States	448,892	2,917,031	935,063	$ 2,971,142	41,126	370,224	102,830
South Africa	471	38,624	6,909	64,861	2,405	10,232	4,110
Tunisia	13,587	24,104	17,604	151,384	6,178	2,367	6,573
Total	462,950	2,979,759	959,576	$ 3,187,387	49,709	382,823	113,513

(a) The gas reserves contain 360,340 MMcf of gas that will be produced and utilized as field fuel.

(b) The 2008 average daily sales volumes are from continuing operations and (i) do not include the field fuel produced, which averaged 51,288 Mcf per day, and (ii) were calculated using a 366-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2008 (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
2009	1,183	$ 39,533	$ 4,635	$ 144,456	$ (109,558)
2010	3,847	121,057	23,188	408,401	(310,532)
2011	7,682	229,643	50,089	472,947	(293,393)
2012	10,556	305,133	73,332	386,316	(154,515)
2013	13,025	372,475	97,035	335,786	(60,346)
Thereafter	369,397	11,677,398	3,568,436	2,634,232	5,474,730
	405,690	$ 12,745,239	$ 3,816,715	$ 4,382,138	$ 4,546,386

(a) Beginning in 2009 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling in 2009 and thereafter.

Description of Properties

United States

Approximately 88 percent of the Company's proved reserves at December 31, 2008 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 2008:

	Development Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	10	363	367	3	3
Mid-Continent	—	6	3	3	—

Rocky Mountains	—	142	139	1	2
Onshore Gulf Coast	—	11	11	—	—
Barnett Shale	—	3	3	—	—
Alaska	—	5	3	—	2
Total United States	10	530	526	7	7

	Exploration/Extension Drilling				
	Beginning Wells In Progress	**Wells Spud**	**Successful Wells**	**Unsuccessful Wells**	**Ending Wells In Progress**
Rocky Mountains	18	17	16	15	4
Onshore Gulf Coast	3	25	24	1	3
Barnett Shale	1	18	16	1	2
Alaska	1	—	—	—	1
Total United States	23	60	56	17	10

The following table summarizes the Company's United States costs incurred by geographic area during 2008:

	Property Acquisition Costs					
	Proved	**Unproved**	**Exploration Costs**	**Development Costs**	**Asset Retirement Obligations**	**Total**
	(in thousands)					
Permian Basin	$ 14,022	$ 16,255	$ 5,053	$ 473,565	$ 13,562	$ 522,457
Mid-Continent	5	—	56	12,962	2,299	15,322
Rocky Mountains	1,132	2,812	65,515	141,105	1,966	212,530
Gulf of Mexico	—	—	(86)	(59)	1,072	927
Onshore Gulf Coast	27,726	22,440	187,545	99,468	1,075	338,254
Barnett Shale	42,359	7,451	55,075	13,294	1,711	119,890
Alaska	—	1,168	8,792	100,980 (a)	128	111,068
Total United States	$ 85,244	$ 50,126	$ 321,950	$ 841,315	$ 21,813	$ 1,320,448

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(a) Includes $18.9 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. 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 9,300 feet to 10,300 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. During 2008, the Company drilled and completed eleven 20-acre wells with encouraging results and an additional nine wells are in various stages of the completion and connection process. During the second half of 2008, in conjunction with its recovery improvement initiatives, the Company applied to the Railroad Commission of Texas to change the Spraberry Trend area field rules to permit drilling of optional 20-acre infill wells. The fieldwide rule changes were approved during January 2009.

The Company has also identified waterflood, non-traditional shale/silt interval and horizontal well initiative opportunities in the Spraberry field. The Company's Spraberry field waterflood project includes plans to convert select wells to water injection in 2009 and potentially drill additional injection wells in the second half of 2009, subject to improved commodity prices. Water injection into converted wells could commence as early as the second quarter 2009. The Company is continuing to test shale/silt non-traditional intervals in ten wells that were completed in 2008.

The 20-acre well spacing and other initiatives described above are being performed 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.

In 2008, the Company acquired approximately 13,000 gross acres in the Spraberry field for $11.0 million. The transaction included 23 producing wells, an incremental working interest increase in 112 wells already operated by Pioneer and a number of undeveloped drilling locations. Proved reserves associated with the acquisition were approximately 2.2 MMBOE.

During 2008, the Company also (i) drilled 370 wells in the Spraberry field, an increase of six percent compared to 2007, (ii) acquired approximately 77,000 gross acres, bringing its total acreage position to approximately 920,000 gross acres (780,000 net acres), (iii) completed several property acquisitions and joint ventures and (iv) successfully drilled a majority of its Spraberry field wells to the Wolfcamp formation. The Company’s 2009 drilling program has been curtailed until commodity prices increase and well costs decline. The

Company has reduced its operating rig count in the Spraberry field to one rig in mid-February from a peak of 17 rigs during 2008.

Midkiff-Benedum Gas Processing System. The Company owns a 27 percent interest in the Spraberry Midkiff-Benedum gas processing system (the "System") in West Texas and, in July 2007, entered into an agreement with Atlas Pipeline Partners ("Atlas") under which the Company obtained options to purchase an additional aggregate 22 percent interest in the System for $230 million, subject to normal closing adjustments. All or a portion of the options must be exercised by November 2, 2009. Any portion of the options not exercised by that date will lapse. Based on current commodity prices, the Company does not expect to exercise the options.

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 500 wells. The Company owns substantially all of the gathering and processing facilities, primarily the Satanta plant, which service its production from the Hugoton field. This ownership allows the Company to control the production, gathering, processing and sale of its 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 Btuand 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. 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 1,000 Btu. The Company owns the majority of the well servicing and frac 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.

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The Company's Raton Basin production volumes increased 17 percent during the twelve months ended December 31, 2008, as compared to the twelve months ended December 31, 2007. The production growth is principally attributable to production added from properties acquired by the Company in December 2007 and production added from the Company's ongoing development drilling program. During 2008, the Company announced a discovery in the Pierre Shale that lies beneath a portion of the Company's Raton Basin coal bed methane acreage. The Company remains encouraged by the drilling and testing results to-date from three Pierre Shale zones, which are producing from vertical wells, and from two horizontal Pierre Shale wells. Initial results from the horizontal drilling indicate a high frequency of natural fracturing with differing production rates from the two wells tied to the occurrence of open fractures. During the twelve months of 2008, the Company drilled 146 wells in the Raton CBM field and 11 wells in the Pierre Shale, along with two water disposal wells. The Company is also enhancing its gathering and compression facilities in the area. To accommodate longer-term production growth in the Raton Basin, the Company added firm pipeline capacity to transport 75 MMcfpd from the Raton Basin to the West Coast gas markets beginning in 2011.

Onshore Gulf Coast

In 2008, the South Texas drilling program focused on the Edwards Trend, a tight gas limestone reservoir extending over 250 miles in length and characterized by narrow bands of dry gas fields. The Company has acquired over 310,000 gross acres in the Edwards Trend. The Company's South Texas drilling program is focused in both established areas, such as the Pawnee field, and in growth areas along the trend, such as the new Moray field discovery. In addition to the Pawnee and Moray fields, the Company has operations in the S.W. Kenedy, Sawfish, Word, Three Rivers and Washburn fields. Productive depths in the Edwards Trend range from 9,500 feet to 14,500 feet.

The Company drilled its first horizontal well in the Eagle Ford Shale play where it holds a substantial acreage position in the gas window. The Eagle Ford Shale play overlays the Edwards Trend in the 310,000 acres that the Company holds. Current plans are to fracture stimulate the well in late March or early April 2009.

During 2008, the Company drilled 11 development wells and spud 25 exploration and extension wells. All 11 development wells were completed successfully. The exploration and extension wells were designed to identify new fields as well as further delineate previous discoveries. Of the 28 exploration and extension wells spud and evaluated, two are temporarily suspended awaiting the drilling of their lateral sections, one is awaiting completion, one was a dry hole and 24 were successfully completed and are currently producing. Three new fields were discovered during 2008.

The acquisition of 3-D seismic data has significantly enhanced field development in all areas of the Edwards Trend, allowing the Company to more accurately locate and orient the horizontal wells for optimal results. Expanding its 3-D data coverage to include new discoveries and additional prospects, the Company has completed a program of shooting 900 square miles of new data. The acquisition of this data has been ongoing since 2007.

In order to accommodate its growing Edwards Trend production, the Company significantly expanded its existing gas gathering and processing infrastructure during 2008. The expansion included constructing over 28 miles of gathering system pipeline, building three additional operated gas treatment plants and connecting to two additional non-operated gas treatment plants.

Barnett Shale

During 2008, the Company participated in the drilling of 19 successful exploration and development wells in the Barnett Shale play in Wise and Parker counties, Texas on both operated and non-operated properties. Another two wells were drilled, but were not completed at the end of 2008. In addition, two non-producing wells were acquired, successfully fracture stimulated and placed on production. During 2008, the Company enhanced its Barnett Shale acreage position through leasing and acquisitions, acquired approximately 250 square miles of 3-D seismic data and improved its operations through compression optimization projects.

The Company’s total holdings in the Barnett Shale play now approximate 70,000 gross acres with more than 500 potential drilling locations, most of which is covered 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.

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. In mid-July 2008, production was shut in for scheduled maintenance at third-party onshore production facilities. Following the completion of the maintenance work in late-September 2008, production resumed. Net production from the project averaged 3,469 barrels during the fourth quarter of 2008 and initial production from the most recent well completed was approximately 7,000 gross Bbls of oil per day. During 2009, development drilling on the Oooguruk project will continue and the Company expects to drill and complete approximately three injection wells and four planned producing wells.

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 will continue to evaluate the Hansen #1A L1, carry forward with permitting, progress engineering studies and develop plans for a second well to be drilled in 2010 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 table summarizes the Company's international exploration/extension drilling activities during 2008:

	Exploration/Extension Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Tunisia	1	12	6	2	5

The following table summarizes the Company's international costs incurred by geographic area during 2008:

	Exploration	Development	Asset Retirement

	Costs	Costs	Obligations	Total
	(in thousands)			
South Africa	$ 145	$ 4,826	$ 2,235	$ 7,206
Tunisia	103,732	28,061	1,452	133,245
Total International	$ 103,877	$ 32,887	$ 3,687	$ 140,451

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 reinjected 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 includes the 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 wells resumed production in late-October. The Sable gas well is expected to be 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 covered approximately 1,240 square kilometers. Over the past three years, the Company has conducted an exploration program over the area. As a result of a seismic data acquisition and exploration drilling program, the Company 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 drilled fourteen wells in the concession and first production from the concession was achieved in late 2007. During 2008, gross production from the Cherouq Concession was approximately 2.5 million barrels.

The Company plans to complete the processing of 295 square kilometers of 3-D seismic data that was acquired during 2008 over the Cherouq Concession.

- **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 now has a 20 percent working interest. During 2008, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling four successful wells and began drilling two wells in the Borj El Khadra Permit, of which one was successful and one was in progress at year end, but subsequent to year end, was determined to be uneconomical.. The Company plans to drill up to four additional wells in the Adam Concession and Borj El Khadra Permit during 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. In 2008, the Company completed processing of 310 kilometers of seismic data and drilled one unsuccessful exploration well. The Company plans on further interpretation of the seismic data during 2009.

- **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 2008, the Company acquired an additional 900 square kilometers of 3-D seismic data and drilled one successful exploration well. The Company plans to complete the processing and interpretation of the seismic data and rill an additional exploration well during 2010.

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, 2008, 2007 and 2006. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The following tables set forth production, price and cost data with respect to the Company's properties for 2008, 2007 and 2006. 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, 2008			
	United States	**South Africa**	**Tunisia**	**Total**
Production information:				
Annual sales volumes:				
Oil (MBbls)	8,068	880	2,261	11,209
NGLs (MBbls)	6,984	—	—	6,984
Gas (MMcf)	135,502	3,745	866	140,113
Total (MBOE)	37,636	1,504	2,406	41,546
Average daily sales volumes:				
Oil (Bbls)	22,044	2,405	6,178	30,627
NGLs (Bbls)	19,082	—	—	19,082
Gas (Mcf)	370,224	10,232	2,367	382,823
Total (BOE)	102,830	4,110	6,573	113,513
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 67.43	$ 110.21	$ 90.64	$ 75.47
NGL (per Bbl)	$ 51.34	$ —	$ —	$ 51.34
Gas (per Mcf)	$ 7.68	$ 5.83	$ 12.04	$ 7.66
Revenue (per BOE)	$ 51.63	$ 79.00	$ 89.53	$ 54.82
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 96.21	$ 110.21	$ 90.64	$ 96.19
NGL (per Bbl)	$ 51.59	$ —	$ —	$ 51.59
Gas (per Mcf)	$ 7.41	$ 5.83	$ 12.04	$ 7.40
Revenue (per BOE)	$ 56.88	$ 79.00	$ 89.53	$ 59.57
Average costs (per BOE):				
Production costs:				
Lease operating	$ 7.79	$ 25.98	$ 6.26	$ 8.37
Third-party transportation charges	1.04	—	1.93	1.06
Net natural gas plant/gathering	0.11	—	—	0.11
Taxes:				
Ad valorem	1.56	—	—	1.41
Production	2.82	—	—	2.55
Workover	0.92	—	—	0.83
Total	$ 14.24	$ 25.98	$ 8.19	$ 14.33
Depletion expense	$ 11.72	$ 18.37	$ 5.96	$ 11.62

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2007			
	United States	South Africa	Tunisia	Total
Production information:				
Annual sales volumes:				
Oil (MBbls)	6,804	979	1,403	9,186
NGLs (MBbls)	6,771	—	—	6,771
Gas (MMcf)	115,493	1,037	917	117,447
Total (MBOE)	32,825	1,151	1,557	35,533
Average daily sales volumes:				
Oil (Bbls)	18,643	2,681	3,845	25,169
NGLs (Bbls)	18,553	—	—	18,553
Gas (Mcf)	316,418	2,840	2,513	321,771
Total (BOE)	89,933	3,154	4,264	97,351
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 63.78	$ 76.36	$ 70.04	$ 66.08
NGL (per Bbl)	$ 41.60	$ —	$ —	$ 41.60
Gas (per Mcf)	$ 7.25	$ 6.76	$ 8.77	$ 7.26
Revenue (per BOE)	$ 47.30	$ 70.98	$ 68.33	$ 48.99
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 70.26	$ 76.72	$ 70.04	$ 70.91
NGL (per Bbl)	$ 41.60	$ —	$ —	$ 41.60
Gas (per Mcf)	$ 6.02	$ 6.76	$ 8.77	$ 6.04
Revenue (per BOE)	$ 44.31	$ 71.29	$ 68.33	$ 46.24
Average costs (per BOE):				
Production costs:				
Lease operating	$ 6.38	$ 22.43	$ 3.46	$ 6.75
Third-party transportation charges	0.97	—	1.57	0.97
Net natural gas plant/gathering	0.16	—	—	0.16
Taxes:				
Ad valorem	1.33	—	—	1.23
Production	2.12	—	—	1.96
Workover	0.83	—	0.11	0.77
Total	$ 11.79	$ 22.43	$ 5.14	$ 11.84
Depletion expense	$ 10.27	$ 12.07	$ 5.01	$ 10.10

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2006			
	United States	South Africa	Tunisia	Total
Production information:				
Annual sales volumes:				
Oil (MBbls)	6,467	1,506	871	8,844
NGLs (MBbls)	6,748	—	—	6,748
Gas (MMcf)	103,928	—	436	104,364
Total (MBOE)	30,536	1,506	944	32,986
Average daily sales volumes:				
Oil (Bbls)	17,716	4,127	2,386	24,229
NGLs (Bbls)	18,488	—	—	18,488
Gas (Mcf)	284,732	—	1,195	285,927
Total (BOE)	83,659	4,127	2,585	90,371
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 65.73	$ 65.92	$ 63.16	$ 65.51
NGL (per Bbl)	$ 35.24	$ —	$ —	$ 35.24
Gas (per Mcf)	$ 6.15	$ —	$ 5.97	$ 6.15
Revenue (per BOE)	$ 42.64	$ 65.92	$ 61.05	$ 44.23
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 62.92	$ 65.74	$ 63.16	$ 63.42
NGL (per Bbl)	$ 35.24	$ —	$ —	$ 35.24
Gas (per Mcf)	$ 5.96	$ —	$ 5.97	$ 5.96
Revenue (per BOE)	$ 41.37	$ 65.74	$ 61.05	$ 43.04
Average costs (per BOE):				
Production costs:				
Lease operating	$ 5.83	$ 14.47	$ 1.99	$ 6.13
Third-party transportation charges	0.81	—	1.42	0.79
Net natural gas plant/gathering	(0.19)	—	—	(0.19)
Taxes:				
Ad valorem	1.45	—	—	1.35
Production	1.99	—	—	1.84
Workover	0.72	—	—	0.66
Total	$ 10.61	$ 14.47	$ 3.41	$ 10.58
Depletion expense	$ 9.07	$ 6.28	$ 4.25	$ 8.80

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, 2008, 2007 and 2006:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
As of December 31, 2008:						
United States	5,374	4,988	10,362	4,561	4,385	8,946
South Africa	—	6	6	—	3	3
Tunisia	28	—	28	8	—	8
Total	5,402	4,994	10,396	4,569	4,388	8,957
As of December 31, 2007:						
United States	5,134	4,774	9,908	4,255	4,383	8,438
South Africa	3	5	8	1	2	3
Tunisia	13	—	13	3	—	3
Total	5,150	4,779	9,929	4,259	4,185	8,444
As of December 31, 2006:						
United States	4,889	4,253	9,142	3,916	3,932	7,848
Canada	48	832	880	31	699	730
South Africa	4	2	6	2	1	3
Tunisia	10	—	10	2	—	2
Total	4,951	5,087	10,038	3,951	4,632	8,583

(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, 2008, the Company owned interests in five 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, 2008:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**	**Acreage**
United States:					
Onshore	1,492,245	1,272,613	2,364,966	1,364,864	299,793
Offshore	51,840	17,834	36,123	31,789	6,750
	1,544,085	1,290,447	2,401,089	1,396,653	306,543

South Africa	119,579	53,281	3,508,421	1,578,790	—
Tunisia	287,540	80,044	2,860,487	1,569,116	—
Total	1,951,204	1,423,772	8,769,997	4,544,559	306,543

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2008:

	Acres Expiring (a)	
	Gross	**Net**
2009 (b)	709,204	393,446
2010	1,459,093	877,318
2011	1,041,680	560,341
2012	121,283	92,070
2013	117,735	100,256
Thereafter	5,321,002	2,521,129
Total	8,769,997	4,544,559

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

(b) All acres subject to expiration during 2009 are in North America. The Company may extend the leases prior to their expiration based upon 2009 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 2008, 2007 and 2006. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry holes.

DRILLING ACTIVITIES

	Gross Wells			Net Wells		
	Year Ended December 31,			Year Ended December 31,		
	2008	2007	2006	2008	2007	2006
United States:						
Productive wells:						
Development	526	602	662	504	581	619
Exploratory	56	41	52	46	33	42
Dry holes:						
Development	7	2	8	7	2	7
Exploratory	17	5	8	9	3	6
	606	650	730	566	619	674
Argentina:						
Productive wells:						
Development	—	—	14	—	—	14
Exploratory	—	—	4	—	—	4
Dry holes:						
Development	—	—	1	—	—	1
Exploratory	—	—	2	—	—	2
	—	—	21	—	—	21
Canada:						
Productive wells:						
Development	—	1	2	—	1	2
Exploratory	—	7	326	—	5	297
Dry holes:						
Development	—	1	—	—	—	—
Exploratory	—	6	16	—	5	15
	—	15	344	—	11	314
South Africa:						
Productive wells:						
Development	—	3	2	—	1	1
Exploratory	—	—	—	—	—	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	—	—	1	—	—	1
	—	3	3	—	1	2
Tunisia:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	6	12	2	3	8	1
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	2	4	2	1	3	—
	8	16	4	4	11	1
West Africa:						
Productive wells:						

Development	—	—	—	—	—	—
Exploratory	—	—	—	—	—	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	—	1	1	—	—	—
	—	1	1	—	—	—
Total	614	685	1,103	570	642	1,012
Success ratio (a)	96 %	97 %	96 %	97 %	98 %	97 %

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(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, 2008:

	Gross Wells	Net Wells
United States:		
Development	7	7
Exploratory	10	9
	17	16
Tunisia:		
Exploratory	5	3
Total	22	19

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 2008.

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 $.30 per share and $.27 per share during each of the years ended December 31, 2008 and 2007, respectively. The Board is currently considering the Company's dividend policy and may decide to reduce the dividend in the near-term to enhance financial flexibility.

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, 2008 and 2007:

	High	Low	Dividends Declared Per Share
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
Year ended December 31, 2007			
Fourth quarter	$ 54.87	$ 42.92	$ —
Third quarter	$ 49.78	$ 35.51	$ 0.14
Second quarter	$ 54.17	$ 42.53	$ —
First quarter	$ 43.62	$ 37.18	$ 0.13

On February 20, 2009, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $15.08 per share.

As of February 20, 2009, the Company's common stock was held by approximately 23,000 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, 2008:

Period	Average Price	Total Number of Shares	Approximate Dollar

	Total Number of Shares (or Units) Purchased (a)	Paid per Share (or Unit)	(or Units) Purchased as Part of Publicly Announced Plans or Programs	Amount of Shares That May Yet Be Purchased Under Plans or Programs
October 2008	986,600	$ 45.96	986,600	
November 2008	2,058,131	$ 24.27	2,058,121	
December 2008	—	$ —	—	
Total	3,044,731	$ 31.30	3,044,721	$372,039,606

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

During February 2007, the Board approved a share repurchase program authorizing the purchase of up to $300 million of the Company's common stock. In April 2007, the Board approved an increase of $450 million to the existing share repurchase program bringing the aggregate authorized share repurchase program to $750 million. During 2008 and 2007, the Company purchased $165.2 million and $212.8 million, respectively, of common stock pursuant to the 2007 program.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data as of and for each of the five years ended December 31, 2008 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)				
	2008	**2007**	**2006**	**2005**	**2004**
	(in millions, except per share data)				
Statements of Operations Data:					
Revenues and other income:					
Oil and gas	$ 2,277.4	$ 1,740.9	$ 1,458.9	$ 1,338.9	$ 962.2
Interest and other (b)	61.3	91.8	43.5	21.2	1.8
Gain (loss) on disposition of assets, net	(0.4)	(2.2)	(6.5)	60.1	0.3
	2,338.3	1,830.5	1,495.9	1,420.2	964.3
Costs and expenses:					
Oil and gas production	595.2	420.7	349.1	309.7	206.1
Depletion, depreciation and amortization	511.8	387.4	314.1	267.8	208.3
Impairment of oil and gas properties (c)	104.3	26.2	—	0.6	39.7
Exploration and abandonments	235.5	279.3	250.2	153.8	94.3
General and administrative	141.8	129.6	116.6	110.1	69.5
Accretion of discount on asset retirement obligations	8.7	7.0	3.7	3.3	3.6
Interest	153.6	135.3	107.0	126.0	102.0
Hurricane activity, net (d)	12.2	61.3	32.0	39.8	—
Minority interest in consolidated subsidiaries’ net income (loss) (e)	21.6	(0.4)	(2.3)	(1.7)	0.9
Other (f)	127.1	29.5	34.3	77.3	24.6
	1,911.8	1,475.9	1,204.7	1,086.7	749.0
Income from continuing operations before income taxes	426.5	354.6	291.2	333.5	215.3
Income tax benefit (provision)	(205.6)	(112.6)	(141.0)	(149.2)	(62.1)
Income from continuing operations	220.9	242.0	150.2	184.3	153.2
Income from discontinued operations, net of tax (a)	(0.8)	130.7	589.5	350.3	159.7
Net income	$ 220.1	$ 372.7	$ 739.7	$ 534.6	$ 312.9
Income from continuing operations per share:					
Basic	$ 1.88	$ 2.01	$ 1.21	$ 1.35	$ 1.22
Diluted	$ 1.86	$ 1.99	$ 1.19	$ 1.32	$ 1.21
Net income per share:					
Basic	$ 1.87	$ 3.10	$ 5.95	$ 3.90	$ 2.50
Diluted	$ 1.85	$ 3.06	$ 5.81	$ 3.80	$ 2.46
Weighted average shares outstanding:					
Basic	117.5	120.2	124.4	137.1	125.2
Diluted	118.6	121.7	127.6	141.4	127.5
Dividends declared per share	$ 0.30	$ 0.27	$ 0.25	$ 0.22	$ 0.20
Balance Sheet Data (as of December 31):					
Total assets	$ 9,163.2	$ 8,617.0	$ 7,355.4	$ 7,329.2	$ 6,733.5
Long-term obligations and minority interests	$ 4,886.0	$ 4,580.1	$ 3,483.7	$ 4,078.8	$ 3,357.2

Total stockholders’ equity	$ 3,582.1	$ 3,042.7	$ 2,984.7	$ 2,217.1	$ 2,831.8

(a) Certain amounts for periods prior to January 1, 2007, have been reclassified (i) in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” (“SFAS 144”) to reflect the results of operations of certain assets disposed of during 2007, 2006 and 2005 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 (ii) to conform to the current year presentation.

(b) Interest and other income in 2008 and 2007 includes $18.6 million and $74.9 million, respectively, of income from Alaskan Petroleum Production Tax (“PPT”) credit dispositions. The Company earns PPT credits on qualifying capital expenditures. The Company recognizes income from PPT credits at the time they are realized through a cash refund or sale. Interest and other income in 2008 includes $23.2 million of gain on extinguishment of debt. See Notes F and M of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(c) During 2008, the Company recorded an impairment charge of $89.8 million to its Uinta/Piceance net assets in western Colorado, as well as a $14.5 million impairment charge to the Company’s net assets in the Mississippi area. During 2007, the Company recorded impairment charges of $10.2 million on Block 320 in Nigeria, $10.3 million related to Block H in Equatorial Guinea and $5.7 million related to properties in the United States for a total of $26.2 million. During 2005 and 2004, the Company recorded $.6 million and $39.7 million of impairment charges for its Gabonese Olowi field because development of the discovery was canceled due to significant increases in projected field development costs. See Note S of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(d) Hurricane activity, net, for 2008, 2007 and 2006 includes $9.0 million, $66.0 million and $75.0 million, respectively, of charges to reclaim and abandon the East Cameron facilities destroyed by Hurricane Rita. In 2006, the Company recorded $43.0 million of estimated insurance recoveries associated with debris removal. See Note U of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(e) Minority interest in consolidated subsidiaries’ net income (loss) during 2008 includes $19.2 million related to minority interest in Pioneer Southwest’s net income. See Note B of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding Pioneer Southwest and the Company’s minority interest in consolidated subsidiaries’ net income (loss).

(f) Other expense for 2008 includes $30.1 million of bad debt expense, which includes $19.6 million of SemCrude bad debt expense, $10.6 million of non-hedge derivative losses and $5.7 million of severance tax audit adjustments. Other expense for 2008, 2007 and 2006 included $29.8 million, $8.7 million and $.3 million of idle drilling equipment costs, respectively, resulting from unused and terminated contract commitments. Other expense for 2008 also included $24.8 million of terminated rig costs. Other expense for 2006 and 2005 includes losses on the early extinguishment of debt of $8.1 million and $26.5 million, respectively. Other expense for 2008, 2007, 2006, 2005 and 2004 includes $0.5 million, $2.1 million, $(10.6) million, $29.8 million and $4.2 million, respectively, of derivative ineffectiveness charges (credits). Other expense for 2007 also includes a $10.6 million postretirement benefit obligation revaluation credit. See Note O of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

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 2008 included the following highlights:

- Net income decreased 41 percent to $220.1 million ($1.85 per diluted share) in 2008 from $372.7 million ($3.06 per diluted share) in 2007, primarily due to Uinta/Piceance and Mississippi asset impairment charges recorded during 2008, an increase in effective income tax rates during 2008 and net income in 2007 including a $101.3 million gain on the sale of Canada and income from discontinued operations in Canada.
- Income from continuing operations decreased to $220.8 million ($1.86 per diluted share) for 2008, as compared to $242.0 million ($1.99 per diluted share) for 2007, primarily due to the aforementioned impairment charges and a higher effective income tax rate
- Average daily sales volumes, on a BOE basis, increased 17 percent in 2008 as compared to 2007, primarily due to successful drilling programs, core area acquisitions and a 12 percent decrease in the delivery of VPP volumes.
- Oil and gas revenues increased $536.5 million, or 31 percent in 2008, as compared to 2007, due to a combination of increased production and increases in commodity prices. The benefit of this increase was partially offset by a $174.5 million increase in production costs compared to 2007, principally as a result of higher energy-related costs and service cost inflation.
- Net cash provided by operating activities increased by $249.9 million, or 32 percent as compared to 2007, primarily due to increased sales volumes and increased commodity prices.
- The Company's Alaskan Oooguruk project began first production and sales during 2008.
- The Company received approval for optional 20-acre downspacing fieldwide in the Spraberry field, significantly increasing development opportunities in the field.
- Pioneer Southwest completed its initial public offering of 9,487,500 common units representing limited partner interests, with the Company realizing total net proceeds of $166.0 million.
- The Company purchased 4.4 million shares of its common stock at an aggregate cost of $165.2 million under the Company's share repurchase program.
- The Company initiated cost reduction initiatives in response to significant commodity price declines experienced during the third and fourth quarters of 2008.

Significant Events

Financial markets. During the second half of 2008, worldwide financial markets experienced significant turmoil as concerns regarding a worldwide economic slowdown increased and the availability of liquidity provided by the financial markets declined. These concerns have continued into the first quarter of 2009. In response to these circumstances, governments worldwide have taken steps to enhance confidence in and support for the financial markets and have announced economic stimulus programs. The success of these actions and the duration of the uncertainty in financial markets cannot be predicted. The Company is closely monitoring the economic environment, including whether and to what extent sustained lower commodity prices could impact its short-term liquidity. Longer-term, depending on the severity and duration of the worldwide economic decline, these market conditions could negatively impact the Company's liquidity, financial position and future results of operations.

As of December 31, 2008, the Company had $48.3 million of cash and cash equivalents and $3.0 billion in outstanding long-term debt, with $541.0 million of liquidity under its senior unsecured credit facility that matures in 2012. The amount of liquidity under the credit facility is subject to a covenant requiring 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. Therefore, the amount that the Company may borrow under the credit facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items. As of December 31, 2008, the Company was also a party to derivative financial instruments, of which $132.2 million represent net assets. Management is closely monitoring the credit standings of its counterparties, including its banks, derivative counterparties and purchasers of the commodities the Company produces and sells.

Commodity prices. The reduced liquidity provided by the worldwide financial markets and other factors have resulted in an economic slowdown in the United States and other industrialized countries which has further resulted in significant reductions in worldwide energy demand. At the same time, North American gas supply has increased as a result of the rise in domestic unconventional gas production during 2008 and prior years. The combination of lower demand due to the economic slowdown and higher North American gas supply has resulted in significant declines in oil, NGL and gas prices from their highs earlier in 2008. These circumstances have led to a dramatic decrease in drilling activity in the industry and has reduced the demand for drilling rigs and vessels, oilfield supplies, drill pipe and utilities, which had reached very high levels in terms of utilization and cost in mid-2008. Although these costs have begun to decline, their declines significantly lag behind the declines in oil, NGL and gas prices. As a result of these circumstances, the Company experienced significant operating margin deterioration during the second half of 2008 and recognized negative price revisions to proved reserves at the end of 2008 due to lower commodity prices and still relatively high capital and operating costs. The duration and magnitude of the commodity price declines cannot be predicted.

Low price environment initiatives. As a result of the significant drop in commodity prices, the Company has implemented initiatives to reduce capital spending, operating costs and general and administrative expenses to support its goal of delivering free cash flow in 2009 and to enhance financial flexibility. This plan includes minimizing drilling activities until margins improve as a result of (i) increased commodity prices, (ii) reduced gas price differentials relative to NYMEX quoted prices in the areas where the Company produces gas and/or (iii) decreased well costs.

During 2009, the Company is undertaking further efforts to reduce its capital, production and administrative costs. Pioneer has reduced its operated rig activity from 29 rigs in the third quarter of 2008 to two rigs drilling in mid-February 2009. The Company is continuing to work with drilling and service providers to reduce drilling and completion costs. To date, Pioneer has achieved reductions of 15 percent to 20 percent in drilling and completion costs and is targeting an additional 10 percent to 20 percent reduction. Rigs have been terminated or stacked in the Spraberry, Raton, Edwards Trend and Barnett Shale areas. The Company's asset teams are also implementing initiatives to reduce controllable production costs, including costs associated with fuel surcharges, electricity supply, water disposal and compression rental.

In 2009, the Company expects capital spending to total $250 million to $300 million (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs). Approximately 75 percent of this amount is for drilling, primarily in Alaska and the Spraberry field. The remaining 25 percent will be used for facility expansions and acreage extensions to Pioneer's core assets.

Hurricanes Gustav and Ike. During the first two weeks of September 2008, Hurricanes Gustav and Ike struck the Louisiana and Texas gulf coasts. The following areas of Texas and Louisiana were adversely impacted:

Spraberry. The Company's Spraberry facilities in West Texas were not directly impacted by either hurricane. The Spraberry field produces oil and associated liquid-rich gas. The gas includes NGLs which are separated at various Permian Basin plants. These NGLs are then transported to a third-party facility in Mont Belvieu, Texas for fractionation. This facility sustained power interruptions and physical damage from Hurricane Ike, disrupting its ability to receive the Company's NGLs. As a result, a portion of the Company's Spraberry and other Permian Basin area production was shut in or curtailed from early September to mid-November while repairs and maintenance to the facility were being completed.

Fort Worth Barnett Shale. The Company's Barnett Shale facilities were not directly impacted by the recent hurricanes. However, as in the Spraberry field, the Company's Barnett Shale gas includes NGLs that are processed at the Mont Belvieu fractionation facilities. The Company experienced only a temporary shut in of its Barnett Shale production, and production was fully resumed by the end of September.

South Texas Edwards Trend. No significant hurricane damage occurred at the Company's facilities in the Edwards Trend area of South Texas. However, power interruptions to third-party pipelines that transport gas production from the field resulted in the temporary curtailment of portions of the Company's total Edwards Trend net production.

Gulf of Mexico Shelf. The Company's shallow-water offshore platforms did not experience any significant damage as a result of the hurricanes. However, production of approximately 1,800 BOEPD was shut in from August 31 to mid-November due to the significant damage that was incurred by the third-party pipeline facilities utilized to transport production to shore.

SemGroup receivables. The Company is a creditor in the bankruptcy of SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), which filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code on July 22, 2008 in the U.S. Bankruptcy Court for the District of Delaware. SemGroup purchased condensate from the Company and, at the time of the bankruptcy filings, was indebted to the Company for $29.6 million. The Company believes that it is probable that the collection of the pre-petition claims will not occur for a protracted period of time and that some of its claims may be uncollectible. Consequently, the Company recorded a bad debt expense of $19.6 million during the second half of 2008, which reduced the carrying value of the claims to $10.0 million.

SemGroup's reorganization effort is still in its early stages and determination of the exact amount of uncollectible claims is not presently determinable. It is reasonably possible that the Company will not collect the claims or that collected amounts will be less than $10.0 million. If those circumstances occur, the Company would recognize additional bad debt expense to further reduce the carrying value of its claims. The Company believes that any losses relating to its failure to collect its SemGroup claims would not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. See Note I of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements" for additional information regarding the Company's SemGroup bankruptcy claims.

First Quarter 2009 Outlook

Based on current estimates, the Company expects that first quarter 2009 production will average 117,000 to 122,000 BOEPD. The range reflects the typical variability in the timing of oil cargo shipments in Tunisia.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $13.50 to $14.50 per BOE based on NYMEX strip prices for oil, NGLs and gas at the time of the estimate. Depletion, depreciation and amortization ("DD&A") expense is expected to average $13.25 to $14.25 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $20 million to $30 million, primarily related to exploration drilling in Tunisia, acreage expirations, and seismic and personnel costs. General and administrative expense is expected to be $32 million to $36 million. Interest expense is expected to be $38 million to $41 million. Accretion of discount on asset retirement obligations is expected to be $2 million to $4 million.

Minority interest in consolidated subsidiaries' net income is expected to be $5 million to $8 million, primarily reflecting the public ownership in Pioneer Southwest.

The Company also expects to recognize $25 million to $30 million of charges in other expense associated with certain drilling rigs being terminated and stacked as a result of the Company's low price environment initiatives.

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 and higher tax rates in certain foreign jurisdictions. Cash income taxes are expected to range from $5 million to $10 million, principally related to Tunisian income taxes.

Acquisitions

2008 acquisition expenditures. During 2008, the Company spent approximately $135.4 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.

2007 acquisition expenditures. During 2007, the Company spent approximately $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.

2006 acquisition expenditures. During 2006, the Company spent approximately $223.2 million to acquire proved and unproved properties, which was comprised of approximately $144.8 million of proved properties and $78.3 million of unproved properties. The proved properties acquired primarily comprise acquisitions in the Spraberry field and Edwards Trend area. In North America, the acquisition of unproved properties was comprised of acreage acquisitions in the Spraberry field, Edwards Trend area, Rockies area, Alaska and Canada. The Company also acquired an additional interest in its Jenein Nord block in Tunisia and recognized additional obligations associated with its Nigerian prospects during 2006.

Divestitures

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

Argentina and Deepwater Gulf of Mexico. During March 2006, the Company sold its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $725.3 million. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. The historic results of these properties and the related gains on disposition are reported as discontinued operations.

Results of Operations

Oil and gas revenues. Oil and gas revenues totaled $2.3 billion, $1.7 billion and $1.5 billion during 2008, 2007 and 2006, respectively. The revenue increase during 2008, as compared to 2007, was primarily reflective of increases in United States, South Africa and Tunisia revenues. 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 reported NGL prices and six percent increases in both reported oil and gas prices. The increase in Tunisian revenues resulted from an increase in average daily sales volumes from successful drilling efforts, a 37 percent increase in reported gas prices and a 29 percent increase in reported oil 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 reported oil prices, partially offset by a 14 percent decrease in reported gas prices.

The revenue increase during 2007, as compared to 2006, was primarily reflective of increases in United States and Tunisian revenues, partially offset by decreases in South African revenues. The increase in United States revenues was primarily due to an increase in average daily sales volumes resulting from successful drilling programs and reductions in scheduled VPP deliveries, combined with an 18 percent increase in reported NGL prices and an 18 percent increase in reported gas prices. The increase in Tunisian revenues resulted from an increase in average daily sales volumes from successful drilling efforts and a 12 percent increase in average reported prices. South African revenues declined due to normal production decline rates in the Sable oil field and the timing of oil cargo liftings, partially offset by increases in average reported oil prices and initial gas production in 2007 from the South Coast Gas project.

The following table provides average daily sales volumes from continuing operations by geographic area and in total, for 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Oil (Bbls):			
United States	22,044	18,643	17,716
South Africa	2,405	2,681	4,127
Tunisia	6,178	3,845	2,386
Worldwide	30,627	25,169	24,229
NGLs (Bbls):			
United States	19,082	18,553	18,488
Gas (Mcf):			
United States	370,224	316,418	284,732
South Africa	10,232	2,840	—
Tunisia	2,367	2,513	1,195
Worldwide	382,823	321,771	285,927
Total (BOE):			
United States	102,830	89,933	83,659
South Africa	4,110	3,154	4,127
Tunisia	6,573	4,264	2,585
Worldwide	113,513	97,351	90,371

On a BOE basis, average daily production for 2008, as compared to 2007, increased by 14 percent in the United States, 30 percent in South Africa and 54 percent in Tunisia. Average daily BOE production for 2007, as compared to 2006, increased by seven percent in the United States and by 65 percent in Tunisia, while average daily production decreased by 24 percent in South Africa.

During the year ended December 31, 2008, oil and gas volumes delivered under the Company's VPPs decreased by 12 percent, as compared to 2007.

The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Oil (Bbls):			
United States	—	—	2,400
Argentina	—	—	2,515
Canada	—	267	311
Worldwide	—	267	5,226
NGLs (Bbls):			
United States	—	—	—
Argentina	—	—	421

Canada	—	371	463
Worldwide	—	371	884
Gas (Mcf):			
United States	—	—	36,038
Argentina	—	—	43,905
Canada	—	44,645	43,434
Worldwide	—	44,645	123,377
Total (BOE):			
United States	—	—	8,406
Argentina	—	—	10,253
Canada	—	8,080	8,013
Worldwide	—	8,080	26,672

The following table provides average reported prices from continuing operations, including the results of hedging activities and the amortization of VPP deferred revenue, and average realized prices from continuing operations, excluding the results of hedging activities and the amortization of VPP deferred revenue, by geographic area and in total, for 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Average reported prices:			
Oil (per Bbl):			
United States	$ 67.43	$ 63.78	$ 65.73
South Africa	$ 110.21	$ 76.36	$ 65.92
Tunisia	$ 90.64	$ 70.04	$ 63.16
Worldwide	$ 75.47	$ 66.08	$ 65.51
NGL (per Bbl):			
United States	$ 51.34	$ 41.60	$ 35.24
Gas (per Mcf):			
United States	$ 7.68	$ 7.25	$ 6.15
South Africa	$ 5.83	$ 6.76	$ —
Tunisia	$ 12.04	$ 8.77	$ 5.97
Worldwide	$ 7.66	$ 7.26	$ 6.15
Total (per BOE):			
United States	$ 51.63	$ 47.30	$ 42.64
South Africa	$ 79.00	$ 70.98	$ 65.92
Tunisia	$ 89.53	$ 68.33	$ 61.05
Worldwide	$ 54.82	$ 48.99	$ 44.23
Average realized prices:			
Oil (per Bbl):			
United States	$ 96.21	$ 70.26	$ 62.92
South Africa	$ 110.21	$ 76.72	$ 65.74
Tunisia	$ 90.64	$ 70.04	$ 63.16
Worldwide	$ 96.19	$ 70.91	$ 63.42
NGL (per Bbl):			
United States	$ 51.59	$ 41.60	$ 35.24
Gas (per Mcf):			
United States	$ 7.41	$ 6.02	$ 5.96
South Africa	$ 5.83	$ 6.76	$ —
Tunisia	$ 12.04	$ 8.77	$ 5.97
Worldwide	$ 7.40	$ 6.04	$ 5.96
Total (per BOE):			
United States	$ 56.88	$ 44.31	$ 41.37
South Africa	$ 79.00	$ 71.29	$ 65.74
Tunisia	$ 89.53	$ 68.33	$ 61.05
Worldwide	$ 59.57	$ 46.24	$ 43.04

Derivative 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. During 2008, 2007 and 2006, the Company's commodity price hedges decreased oil and gas revenues from continuing operations by $355.6 million, $83.5 million and $151.2 million, respectively. The effective portions of changes in the fair values of the Company's commodity price hedges are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedges add volatility to the

Company's reported stockholders' equity until the hedge derivative matures or is terminated. During December 2008, the Company began entering into commodity derivative contracts that were not designated as hedges under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." The changes in the fair value of these instruments are being recognized as gains or losses in the earnings of the period in which they occur. During 2008, the Company's non-hedge derivative contracts increased other expense by $10.6 million. Effective February 1, 2009, the Company discontinued hedge accounting on all existing commodity derivative instruments, and from that date forward will account for derivative instruments using the mark-to-market accounting method. Therefore, the Company will recognize all future changes in the fair values of its derivative contracts as gains or losses in the earnings of the period in which they occur. See Note J of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information concerning the impact to oil and gas revenues during 2008, 2007 and 2006 from the Company’s hedging activities, the Company’s open and terminated derivative positions at December 31, 2008 and descriptions of the Company’s commodity derivatives. Also see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for additional disclosures about the Company’s commodity related derivative financial instruments.

Deferred revenue. During 2008, 2007 and 2006, the Company’s recognition of previously deferred VPP revenue increased oil and gas revenues from continuing operations by $158.1 million, $181.2 million and $190.3 million, respectively. The Company’s amortization of deferred VPP revenue is scheduled to increase 2009 oil and gas revenues by $147.9 million. See Note T of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for specific information regarding the Company’s VPPs.

Interest and other income. The Company’s interest and other income totaled $61.3 million, $91.9 million and $43.5 million during 2008, 2007 and 2006, respectively. The $30.5 million decrease during 2008, as compared to 2007, is primarily attributable to (i) a $56.2 million decrease in Alaskan Petroleum Production Tax (“PPT”) credit dispositions, partially offset by (ii) a $23.2 million gain on bond repurchases. The $48.4 million increase during 2007, as compared to 2006, is primarily attributable to (i) $74.9 million of 2007 Alaskan PPT credit dispositions offset by (ii) an $11.3 million decrease in interest income, (iii) a $7.6 million reduction in business interruption insurance claims and (iv) a $7.4 million decrease in derivative ineffectiveness income.

In 2006, Alaska replaced its severance tax with the PPT for periods beginning after March 31, 2006. In late 2007, Alaska made further changes to the PPT through legislation referred to as “Alaska’s Clear and Equitable Share” (“ACES”). The ACES modifications to PPT were effective as of July 1, 2007. Due to the Company’s expenditures in Alaska before beginning production, the Company generated PPT related carryforwards. At December 31, 2008, the Company had approximately $89.0 million of available PPT related carryforwards that may be monetized in the future. The Company anticipates recognizing further benefits from the PPT related carryforwards from (i) a reduction in PPT liabilities or (ii) sales of the carryforwards to third parties, if transferable, or reimbursement from the State of Alaska. The Company anticipates that any transfers of PPT related carryforwards to third parties would be at a discounted value, for which the amount of discount is currently not known, but is not expected to be significant.

Gain (loss) on disposition of assets. The Company recorded a net loss on disposition of assets of $381 thousand in 2008, as compared to net losses of $2.2 million and $6.5 million in 2007 and 2006, respectively.

During 2007, the Company recognized a gain on the sale of its Canadian assets of $101.3 million. During 2006, the Company recognized gains on the sale of its interest in certain oil and gas properties in the deepwater Gulf of Mexico and its Argentina assets of approximately $736.2 million. However, pursuant to SFAS 144, these gains and the results of operations from the assets are presented as discontinued operations.

The net cash proceeds from asset divestitures during 2008, 2007 and 2006 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and stock repurchase programs, and to reduce outstanding indebtedness. See Notes N and V of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding asset divestitures.

Oil and gas production costs. The Company’s oil and gas production costs totaled $595.2 million, $420.7 million and $349.1 million during 2008, 2007 and 2006, respectively. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while production taxes and ad valorem taxes are directly related to commodity price changes. Third-party transportation charges represent costs incurred directly from interstate carriers associated with the delivery of oil and gas products from the lease to a downstream point of sale and are based on volumes delivered.

Total production costs per BOE increased during 2008 by 21 percent as compared to 2007 primarily due to increases in production taxes due to commodity price increases and increases in lease operating expense. The increase in lease operating expenses is primarily due to (i) fixed production costs associated with first sales from the Alaskan Oooguruk development project, (ii) fixed production costs associated with the Company's South African Sable oil field production, prior to its shut in in September 2008, (iii) production operations in the Tunisian Cherouq concession, (iv) unscheduled compressor repairs and maintenance in the Raton field and (v) general inflation of field service costs and electricity charges.

Total production costs per BOE increased during 2007 by 12 percent as compared to 2006 primarily due to (i) general inflation of field service and supply costs associated with rising commodity prices, (ii) increased repair and clean up costs, and associated production downtime, from severe weather conditions that affected certain areas of the Company's United States operations during the first quarter of 2007, (iii) increased workover activity and (iv) fixed production costs associated with declining South African Sable oil production.

The following tables provide the components of the Company's total production costs per BOE and total production costs per BOE by geographic area for 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Lease operating expenses	$ 8.37	$ 6.75	$ 6.13
Third-party transportation charges	1.06	0.97	0.79
Net natural gas plant/gathering	0.11	0.16	(0.19)
Taxes:			
Ad valorem	1.41	1.23	1.35
Production	2.55	1.96	1.84
Workover costs	0.83	0.77	0.66
Total production costs	$ 14.33	$ 11.84	$ 10.58

	Year Ended December 31,		
	2008	**2007**	**2006**
United States	$ 14.24	$ 11.79	$ 10.61
South Africa	$ 25.98	$ 22.43	$ 14.47
Tunisia	$ 8.19	$ 5.14	$ 3.41
Worldwide	$ 14.33	$ 11.84	$ 10.58

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $12.32, $10.90 and $9.52 per BOE for 2008, 2007 and 2006, respectively. Depletion expense, the largest component of DD&A expense, was $11.62, $10.10 and $8.80 per BOE during 2008, 2007 and 2006, respectively. During 2008, the increase in per BOE depletion expense was primarily due to (i) losing end-of-well-life reserves that became uneconomic as a result of lower 2008 year-end commodity prices, (ii) a generally increasing trend in the Company's oil and gas properties' cost bases per BOE of total proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies and (iii) the relatively higher depletion rate per BOE associated with production from the Oooguruk development and South African South Coast Gas projects.

During 2007, the increase in per BOE depletion expense was primarily due to (i) a generally increasing trend in the Company's oil and gas properties' cost bases per BOE of total proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies and (ii) first production of the South Coast Gas project in South Africa, which has a higher depletion rate.

The following table provides depletion expense per BOE from continuing operations by geographic area for 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
United States	$ 11.72	$ 10.27	$ 9.07
South Africa	$ 18.37	$ 12.07	$ 6.28
Tunisia	$ 5.96	$ 5.01	$ 4.25
Worldwide	$ 11.62	$ 10.10	$ 8.80

Impairment of oil and gas properties and other assets. The Company reviews its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. During the year ended December 31, 2008, the Company recognized impairment charges of $104.3 million to reduce the carrying value of the Company's net assets in the Uinta/Piceance and Mississippi areas. The declines in gas prices during the second half of 2008 led to the impairment charge.

During the year ended December 31, 2007, the Company recognized aggregate noncash impairment charges of $26.2 million. During 2007, the Company recorded a charge of $10.3 million to write off the Company's remaining basis in Block H in Equatorial Guinea. The charge was recorded in connection with an arbitration that was active among the parties participating in the Block H prospect. Another $10.2 million of the impairment charges related to the Company's announcement of its intent to dispose of its Nigerian subsidiary that held an interest in Block 320 and the resulting adjustment to reduce its cost basis to Block 320's estimated fair value. During the second quarter of 2007, the Company also recognized a $5.7 million impairment charge to reduce the carrying values of certain oil and gas properties located in Louisiana due to poor well performance.

The commodity price declines in the second half of 2008 also provided indications that the Company's $310.6 million carrying value of goodwill and $237.2 million carrying value of the South African South Coast Gas project may have been impaired as of December 31, 2008. After performing impairment evaluations, the Company determined that its goodwill and South African South Coast Gas project were not impaired as of December 31, 2008. However, continuation of commodity price declines during the first quarter of 2009 indicates that these assets may be at risk for future impairment and that the Uinta/Piceance assets may be at risk for further impairment. See Note S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding these impairment risks and factors that affect the determination of impairment charges.

Exploration, abandonments, geological and geophysical costs. The following table provides the Company's geological and geophysical costs, exploratory dry hole expense, leasehold abandonments and other exploration expense by geographic area for 2008, 2007 and 2006:

	United States (in thousands)	South Africa	Tunisia	Other	Total
Year ended December 31, 2008					
Geological and geophysical	$ 79,117	$ 143	$ 22,499	$ —	$ 101,759
Exploratory dry holes	73,742	—	15,130	—	88,872
Leasehold abandonments and other	44,899	—	—	—	44,899
	$ 197,758	$ 143	$ 37,629	$ —	$ 235,530
Year ended December 31, 2007					
Geological and geophysical	$ 91,547	$ 276	$ 2,812	$ 9,182	$ 103,817
Exploratory dry holes	119,638	—	13,931	13,851	147,420
Leasehold abandonments and other	20,453	—	—	7,639	28,092
	$ 231,638	$ 276	$ 16,743	$ 30,672	$ 279,329
Year ended December 31, 2006					
Geological and geophysical	$ 79,140	$ 289	$ 8,402	$ 21,536	$ 109,367
Exploratory dry holes	80,023	7,227	6,214	15,845	109,309
Leasehold abandonments and other	13,696	—	—	17,824	31,520
	$ 172,859	$ 7,516	$ 14,616	$ 55,205	$ 250,196

During 2008, the Company's geological and geophysical expense, exploratory dry hole provisions and leasehold abandonments expense is primarily attributable to seismic activity in the Company's Mississippi, South Texas and Tunisia areas, dry hole expense and unproved property abandonments. The significant components of the Company's exploratory dry hole provisions and leasehold abandonments expense included (i) $47.1 million of costs associated with the unsuccessful Lay Creek CBM pilot project, (ii) $12.2 million of costs associated with the unsuccessful Delaware Basin exploration project, (iii) $11.3 million of costs associated with the unsuccessful Sligo exploration well in South Texas and (iv) $41.1 million of U.S. unproved property abandonments. During 2008, the

Company completed and evaluated 81 exploration/extension wells, 62 of which were successfully completed as discoveries.

The Company's Lay Creek project was a CBM pilot program located in northwestern Colorado. The Company drilled 18 wells in six separate pilot areas and completed workovers and recompletions on 14 wells drilled by a previous operator. The Company completed water treatment facilities and initiated sales of production in the second quarter of 2008. The success of the pilot program was dependent on the ability to dewater the formation and determining that commercial quantities of gas could be produced. During October 2008, the Company concluded that the project was not commercial and abandoned future dewatering activities. Consequently, the Company recorded a charge of $47.1 million to exploration and abandonments expense in the accompanying consolidated statements of operations for the year ended December 31, 2008, to eliminate the carrying value of the Lay Creek project.

During 2007, significant components of the Company's exploratory dry hole provisions and leasehold abandonments expense included: (i) $72.1 million of suspended well costs written off due to the discontinuation of the Clipper project in the deepwater Gulf of Mexico due to increasing costs, (ii) $13.8 million of costs associated with the Company's unsuccessful exploratory well on its Block 256 offshore Nigeria, (iii) $50.8 million for costs associated with two unsuccessful exploratory wells in the Company's Alaskan National Petroleum Reserve area and the write-off of the remaining prospect costs in the onshore Alaskan North Slope area and (iv) $13.9 million of Tunisian dry hole provisions and abandonment costs, which primarily related to the write-off of a suspended well drilled in 2003 on the Anaguid permit and an unsuccessful exploratory well in both the Jenein Nord permit and the Borj El Khadra permit. During 2007, the Company's seismic activity primarily related to its resource plays in South Texas and the Rocky Mountains. During 2007, the Company completed and evaluated 76 exploration/extension wells, 60 of which were successfully completed as discoveries.

During 2006, significant components of the Company's dry hole provisions and leasehold abandonments expense included (i) $34.0 million of costs associated with the Company's unsuccessful exploratory well on its Block 256 prospect offshore Nigeria, including $17.8 million of associated unproved leasehold impairment, (ii) $21.6 million of dry hole provisions recorded for the Company's unsuccessful Cronus, Storms and Antigua prospects in the North Slope area of Alaska, (iii) $16.9 million of dry hole provisions and abandonment costs recognized on prospects drilled in prior periods that were being evaluated for commerciality, including $7.2 million of costs associated with the Company's Boomslang prospect offshore South Africa, $5.5 million of costs associated with two discoveries on the Gulf of Mexico shelf in 2005 and $4.2 million of costs associated with the Company's Anaguid permit in Tunisia, (iv) $16.0 million of dry hole provision and unproved property impairment recognized on the Company's unsuccessful Norphlet prospect in Mississippi and (v) a $14.3 million charge associated with an unsuccessful well on the Company's Flying Cloud prospect in the Gulf of Mexico. During 2006, the Company completed and evaluated 414 exploration/extension wells, 384 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled $141.8 million, $129.6 million and $116.6 million during 2008, 2007 and 2006, respectively. The increase in general and administrative expense during 2008, as compared to 2007, was primarily due to (i) expenses associated with the administration of Pioneer Southwest and (ii) continuing increases in performance-related compensation costs, including the amortization of share-based compensation to officers, directors and employees. As of December 31, 2008, the Company has $48.3 million of unrecognized compensation expense related to unvested share-based awards that will be charged to earnings over a weighted average period of less than three years. The Company has initiated cost reduction initiatives in response to commodity price declines experienced during the second half of 2008 and continuing into the first quarter of 2009. See "Significant Events" for information regarding financial markets, commodity prices and low price environment initiatives.

The increase in general and administrative expense during 2007, as compared to 2006, was primarily due to increases in performance related compensation costs, including the amortization of share-based awards to officers, directors and employees.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations from continuing operations was $8.7 million, $7.0 million and $3.7 million during 2008, 2007 and 2006, respectively. The increase in accretion of discount on asset retirement obligations during 2008 and 2007 was primarily due to new wells placed on production. See Note L of Notes to Consolidated Financial

Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

Interest expense. Interest expense was $153.6 million, $135.3 million and $107.1 million during 2008, 2007 and 2006, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2008 was 5.5 percent, as compared to 6.5 percent and 6.7 percent for the years ended December 31, 2007 and 2006, respectively, including the effects of interest rate derivatives. The $18.3 million increase in interest expense during 2008 as compared to 2007 was primarily due to (i) an $18.2 million increase in interest incurred on senior notes due to an increase in average senior note borrowings outstanding, (ii) a $13.6 million decrease in capitalized interest due to the completion of the South African South Coast Gas project during 2007 and declining capitalized interest on the Oooguruk development project in Alaska, partially offset by (iii) a $12.6 million decrease in interest incurred on the Company credit facility due to declining interest rates.

The increase in interest expense for 2007 as compared to 2006 was primarily due to (i) a $44.3 million increase in interest incurred on long-term debt due to a $712 million increase in average debt outstanding, primarily related to funding additions to oil and gas properties, (ii) a $5.4 million increase in noncash interest expense attributable to certain discounted liabilities and deferred hedge losses partially offset by (iii) a $20.4 million increase in capitalized interest on the Company's Oooguruk and South Coast Gas development projects in Alaska and South Africa, respectively.

The Company expects interest expense to increase in future periods due to declining capitalized interest on the Alaskan Oooguruk development project and as the interest expense recorded on the $480 million of outstanding 2.875% convertible senior notes due 2038 (the "2.875% Senior Convertible Notes") increases to an annual rate of 6.75 percent. See "New Accounting Pronouncements – FSP APB 14-1" for information regarding this accounting change. The increase in interest expense associated with the adoption of the new accounting pronouncement will be a noncash expense.

See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's long-term debt and interest expense.

Hurricane activity, net. The Company recorded net hurricane related activity expenses of $12.2 million, $61.3 million and $32.0 million during 2008, 2007 and 2006, respectively, associated with the Company's East Cameron platform facilities, located on the Gulf of Mexico shelf, that were destroyed during 2005 by Hurricane Rita.

The Company estimates that it will cost approximately $22 million to complete operations to reclaim and abandon the East Cameron platform facilities. Since January 2007, the Company has expended approximately $163.1 million on operations to reclaim and abandon the East Cameron platform facilities. The Company's estimates to reclaim and abandon the East Cameron facilities are based upon an analysis prepared by a third party engineering firm for a majority of the work and an estimate by the Company for the remaining work that was not covered by the third-party analysis. During 2007, the Company commenced legal actions against its insurance carriers regarding certain policy coverage issues. The Company continues to expect that a substantial portion of the loss will be recoverable by insurance. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's East Cameron platform facilities reclamation and abandonment.

Minority interest in consolidated subsidiaries' net income (loss). Minority interest in consolidated subsidiaries' net income (loss) from continuing operations during 2008 was a charge to pretax earnings of $21.6 million, as compared to net credits to pretax earnings of $352 thousand and $2.3 million for 2007 and 2006, respectively. The $22.0 million expense increase in 2008, as compared to 2007, is primarily due to $19.2 million of minority interest in the income of Pioneer Southwest and a $2.8 million minority interest in the 2007 net losses of Pioneer Natural Resources Nigeria (320) Limited, which was sold by the Company during 2007.

The $1.9 million decrease in minority interest in consolidated subsidiaries' net loss for 2007, as compared to 2006, is primarily due to a $2.1 million decrease in minority interest in the net losses of Pioneer Natural Resources Nigeria (320) Limited. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding Pioneer Southwest and the Company's minority interest in consolidated subsidiaries' net income (loss).

Other expenses. Other expenses were $127.1 million during 2008, as compared to $29.4 million during 2007 and $34.3 million during 2006. The $97.7 million increase in other expense during 2008, as compared to 2007, is primarily attributable to (i) a $25.0 million increase in bad debt expense, primarily attributable to $19.6 million in bad debt expense related to the SemGroup bankruptcy, (ii) a $24.8 million increase in rig contract termination charges, (iii) a $21.1 million increase in idle drilling equipment costs during 2008 and (iv) a $10.6 million non-hedge derivative loss in 2008.

The $4.9 million decrease in other expense during 2007, as compared to 2006, is primarily attributable to (i) an $11.2 million decrease in the Company's postretirement benefit obligations, (ii) an $8.1 million decrease in losses on early extinguishments of debt, (iii) a $6.5 million decrease in non-hedge derivative charges and (iv) a $4.0 million decrease in insurance charges, partially offset by (v) a $12.7 million increase in charges related to commodity hedge ineffectiveness and (vi) an $8.4 million increase in the cost of idle drilling equipment.

See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's other expenses. During 2009, the Company intends to continue the implementation of cost reduction initiatives, including actions that will result in additional charges for idle drilling equipment and rig contract terminations. See "Significant Events" and "First Quarter 2009 Outlook" above for additional information regarding these initiatives.

Income tax provision. The Company recognized income tax provisions on continuing operations of $205.6 million, $112.6 million and $141.0 million during 2008, 2007 and 2006, respectively. The Company's effective tax rates for 2008, 2007 and 2006 were 48 percent, 32 percent and 48 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 37 percent. The effective tax rates of 2008, 2007 and 2006 differ from the combined United States federal and state statutory rates primarily due to:

- foreign tax rates;
- statutes in foreign jurisdictions that differ from those in the United States, including a South African tax law allowing for the deduction of 150 percent of development expenditures, resulting in a $15.7 million tax benefit in 2007;
- a $40.9 million tax benefit during 2007 related to the Company's exit from Nigeria;
- a $13.8 million tax benefit during 2007 related to the Company's relinquishment of its remaining rights in Gabon and the write off of costs associated with Block H in Equatorial Guinea;
- a $15.8 million and $18.9 million U.S. tax provision during 2008 and 2007, respectively, related to the Company no longer having identifiable plans to reinvest South Africa earnings in South Africa; and
- expenses for unsuccessful well costs and associated acreage costs in foreign locations where the Company does not expect to receive income tax benefits, principally attributable to unsuccessful wells in Nigeria during 2007 and 2006.

See "Critical Accounting Estimates" below and Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's tax position.

Discontinued operations. During 2007 and 2006, the Company sold its interests in the following oil and gas asset groups:

Country	**Description of Asset Groups**	**Date Divested**
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006
Canada	Canadian assets	November 2007

The Company recognized a loss from discontinued operations of $751 thousand during 2008 as compared to gains from discontinued operations of $130.7 million during 2007 and $589.5 million during 2006. Pursuant to SFAS 144, the results of operations of these assets and the related gains on disposition are reported as discontinued operations. See Note V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's discontinued operations.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for capital expenditures and acquisition expenditures on oil and gas assets, payment of contractual obligations, dividends/distributions and working capital obligations. Funding for these cash needs, as well as funding for any stock or debt repurchases that the Company may undertake, may be provided by any combination of internally-generated cash flow, proceeds from the disposition of nonstrategic assets or external financing sources as discussed in "Capital resources" below. The

Company expects that it will be able to fund its needs for cash (excluding acquisitions) with internal operating cash flows. Acquisitions may be funded with internal operating cash flows or availability under the Company's revolving credit facilities. Although the Company expects that internal operating cash flows will be adequate to fund capital expenditures and dividend/distribution payments, and that available borrowing capacity under the Company's credit facilities will provide adequate liquidity to fund future acquisitions, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

The worldwide economic slowdown has negatively impacted the demand for energy and as a result, commodity prices have declined significantly since their highs earlier in 2008. As a result of the significant decline in commodity prices, the Company has implemented initiatives to reduce capital spending, operating costs and general and administrative expenses to enhance and preserve financial flexibility. Specifically, the Company plans to minimize drilling activities until commodity prices increase, gas price differentials in the areas where the Company produces gas narrow relative to NYMEX quoted gas prices and/or well cost reductions can be achieved. As a result, the Company has reduced its rig activity and is pursuing reductions in well costs to align costs with the lower commodity price environment that currently exists. Rigs have been terminated or stacked in the Spraberry, Raton, Edwards Trend and Barnett Shale areas. The Company has reduced its operated rig activity from 29 rigs in the third quarter of 2008 to two rigs during mid-February 2009.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2008, 2007 and 2006 totaled $1.4 billion, $2.1 billion and $1.4 billion, respectively. The Company's 2008 expenditures for additions to oil and gas properties were funded by $1.0 billion of net cash provided by operating activities, $292.9 million of proceeds from the disposition of assets and $166.0 million of proceeds from the initial public offering of Pioneer Southwest's common units representing limited partner interests. The Company's 2007 expenditures for additions to oil and gas properties were funded by $775.3 million of net cash provided by operating activities, the net proceeds from the disposition of Canadian assets and borrowings on the Company's line of credit. The Company's 2006 expenditures for additions to oil and gas properties were funded by $754.8 million of net cash provided by operating activities and by a portion of the net proceeds from the disposition of deepwater Gulf of Mexico and Argentine assets.

The Company strives to maintain its indebtedness at levels that will provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2009 is approximately $250 million to $300 million. The Company currently expects that cash flows from operations will be sufficient to fund the 2009 capital budget.

Off-balance sheet arrangements. From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2008, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, (iv) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future) and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "Contractual obligations" below for more information regarding the Company's off-balance sheet arrangements.

Contractual obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments (including commitments to pay day rates for drilling rigs), derivative obligations, other liabilities, transportation commitments and VPP obligations.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2008:

	Payments Due by Year			
	2009	2010 and 2011	2012 and 2013	Thereafter
	(in thousands)			
Long-term debt (a)	$ —	$ —	$ 919,110	$ 2,119,985
Operating leases (b)	20,072	29,310	25,203	70,803
Drilling commitments (c)	96,968	121,648	37,610	—
Derivative obligations (d)	49,561	20,584	—	—
Other liabilities (e)	93,694	26,034	11,414	149,961
Transportation commitments (f)	25,972	46,202	25,385	21,117
VPP obligations (g)	147,906	135,166	42,069	—
	$ 434,173	$ 378,944	$ 1,060,791	$ 2,361,866

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(a) See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for information regarding estimated future interest payment obligations under long-term debt obligations and Note F of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.” The amounts included in the table above represent principal maturities only.

(b) See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(c) Drilling commitments represent future minimum expenditure commitments for drilling rig services and well commitments under contracts to which the Company was a party on December 31, 2008.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2008. These liabilities include $40.3 million of liabilities that are fixed in amount and are not subject to continuing market risk. The ultimate settlement amounts of the remaining portions of the Company’s derivative obligations are unknown because they are subject to continuing market risk. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and Note J of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the Company’s derivative obligations.

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

(f) Transportation commitments represent estimated transportation fees on gas throughput commitments. See Note I of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the Company’s transportation commitments.

(g) These amounts represent the amortization of the deferred revenue associated with the VPPs. The Company’s ongoing obligation is to deliver the specified volumes sold under the VPPs free and clear of all associated production costs and capital expenditures. See Note T of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

Capital resources. The Company’s primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of nonstrategic assets. Although the Company expects that these resources will be sufficient to fund its capital commitments during the foreseeable future, the recent turmoil in worldwide financial markets have resulted in the availability of external sources of short-term and long-term capital funding being less certain. During 2008, the Company’s net cash provided by operating activities, net proceeds from asset divestitures and net proceeds from Pioneer Southwest’s initial public offering of common units representing limited partner interests were sufficient to fund its additions to oil and gas properties, but insufficient to fund all capital requirements, resulting in additional borrowings under the Company's credit facility. For 2009, the Company currently expects that cash flow from operations will be sufficient to fund the Company's $250 million to $300 million capital budget.

Asset divestitures. During 2008, the Company terminated derivative assets prior to their contractual maturity dates. The accompanying consolidated statement of cash flows for the year ended December 31, 2008 includes approximately $155.0 million of proceeds from disposition of assets attributable to these derivative terminations.

In November 2007, the Company completed the sale of its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. The net proceeds from the sale of the Canadian subsidiaries includes $132.8 million of proceeds that were deposited by the purchaser into the Company's Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications, which were received in January 2008. Accordingly, the accompanying consolidated statements of cash flows for the years ended December 31, 2008 and 2007, include approximately $132.0 million and $392.9 million of proceeds from disposition of assets, net of cash sold, respectively, pertaining to the sale of the Canadian subsidiaries.

During March 2006, the Company sold all of its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $725.3 million. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. The results of operations for these divestitures are included in the Company's discontinued operations. The net cash proceeds from these divestitures were used to reduce outstanding indebtedness under the Company's credit facility, to fund a portion of additions to oil and gas properties, for stock repurchases and for general corporate purposes.

Operating activities. Net cash provided by operating activities during 2008, 2007 and 2006 was $1.0 billion, $775.3 million and $754.8 million, respectively. The increase in net cash provided by operating activities in 2008, as compared to that of 2007, was primarily due to increased sales volumes and increased oil, NGL and gas prices from continuing operations, partially offset by increased production costs. The increase in net cash provided by operating activities in 2007, as compared to that of 2006, was primarily due to increased sales volumes, increased commodity prices and $74.9 million of income realized from the monetization of Alaskan PPT credits.

Investing activities. Net cash used in investing activities during 2008 was $1.2 billion, as compared to net cash used in investing activities of $1.8 billion during 2007 and net cash provided by investing activities of $145.5 million during 2006. The decrease in net cash provided by investing activities during 2008, as compared to 2007, was primarily due to $664.4 million decrease in the additions to oil and gas properties and a $95.2 million decrease in the additions to other assets and other property and equipment, net, partially offset by a decrease of $128.0 million in proceeds from disposition of assets. The decrease in net cash provided by investing activities during 2007, as compared to 2006, was primarily due to $1.6 billion of net proceeds received from the divestiture of assets during 2006, the substantial portion of which resulted from the sale of the Company's deepwater Gulf of Mexico and Argentine assets, and a $663.8 million increase in additions to oil and gas properties during 2007. See "Results of Operations" above and Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Financing activities. Net cash provided by financing activities for 2008 was $162.3 million, as compared to net cash provided by financing activities of $1.0 billion for 2007 and net cash used in financing activities of $913.5 million during 2006. During 2008, significant components of financing activities included $225.8 million of net borrowings under long-term debt and $166.0 million from the proceeds of the Pioneer Southwest IPO, partially offset by $181.5 million used to purchase 4.7 million shares of treasury stock. During 2007, significant components of financing activities included $1.3 billion of net borrowings under long-term debt and $221.4 million of net cash used to purchase 5.2 million shares of treasury stock. During 2006, significant components of financing activities included $554.7 million of net cash used to repay long-term borrowings, $348.9 million of net cash used to purchase 8.9 million shares of stock and $31.7 million of dividend payments, partially offset by $17.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases.

On January 15, 2008, $3.8 million principal amount of the Company's 6.50% senior notes matured and were repaid with borrowings under its credit facility.

During January 2008, the Company issued the 2.875% Senior Convertible Notes and received proceeds, net of approximately $11.3 million of underwriter discounts and offering costs, of approximately $488.7 million. The Company used the net proceeds from the offering to reduce outstanding borrowings under its credit facility. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the 2.875% Senior Convertible Notes.

During April 2008, the Company paid $16.8 million of aggregate dividends ($0.14 per common share). During October 2008, the Company paid $19.2 million of aggregate dividends ($0.16 per common share). Future dividends and the timing and amount thereof are at the discretion of the Board, and the Board is currently considering the Company's dividend policy and may decide to reduce the dividend in the near-term to enhance financial flexibility.

On May 6, 2008, Pioneer Southwest, a subsidiary of the Company, completed its initial public offering of 9,487,500 common units, representing a 31.6 percent limited partner interest in Pioneer Southwest. Pioneer Southwest owns interests in certain oil and gas properties previously owned by the Company in the Spraberry field in the Permian Basin of West Texas. The Company owns a 0.1 percent general partner interest and a 68.3 percent limited partner interest in Pioneer Southwest. The Company received $166.0 million of net proceeds from Pioneer Southwest in consideration for (i) an ownership interest in a subsidiary of the Company that owned the oil and gas properties prior to the initial public offering and (ii) an incremental ownership interest in certain of the same properties as a result of the exercise of the over-allotment option. The net proceeds from the initial public offering were used to reduce the Company’s outstanding indebtedness. The Company consolidates Pioneer Southwest into its financial statements and reflects the public ownership as a minority interest in Pioneer Southwest’s net assets.

In conjunction with the completion of the initial public offering, Pioneer Southwest completed a $300 million unsecured revolving credit facility with a syndicate of banks, which matures in May 2013 (the “Pioneer Southwest Credit Facility”). The Pioneer Southwest Credit Facility is available for general partnership purposes, including working capital, capital expenditures and distributions.

During December 2008, the Company repurchased $20.0 million principal amount of its outstanding $500.0 million of 2.875% Senior Convertible Notes, $71.5 million principal amount of its outstanding $526.9 million of 5.875% senior notes due 2016, $14.9 million principal amount of its outstanding $500.0 million of 6.65% senior notes due 2017 and $500 thousand principal amount of its outstanding $450.0 million of 6.875% senior notes due 2018. Associated therewith, the Company recognized a gain of $23.2 million, which is included in interest and other income in the accompanying consolidated statements of operations.

On August 15, 2007, $32.1 million principal amount of the Company’s 8.25% senior notes matured and were repaid with borrowings under the Company’s credit facility.

During April 2007, the Company amended its existing Amended and Restated $1.5 billion 5-Year Revolving Credit Agreement with an Amended and Restated 5-Year Revolving Credit Agreement (the “Credit Facility”) to extend the maturity and improve the pricing. The Credit Facility provides for initial aggregate loan commitments of $1.5 billion, which may be increased to a maximum aggregate amount of $2.0 billion if the lenders increase their loan commitments or if loan commitments of new financial institutions are added. The Company’s borrowing capacity under the credit facility is subject to a covenant requiring 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. The amount that the Company may borrow under the credit facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items. See Note F of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the significant terms of the amended credit facility. During January 2008, the Company entered into interest rate swap contracts and designated the contracts as cash flow hedges of the forecasted interest rate risk associated with a portion of the Company’s credit facility indebtedness. The interest rate swap contracts are variable-for-fixed-rate swaps on $400 million notional amount of debt at a weighted average fixed annual rate of 2.87 percent, excluding any applicable margins. The interest rate swaps have an effective start date during February 2008, $200 million of which terminates in February 2010, with the remaining $200 million terminating in February 2011.

During March 2007, the Company issued $500.0 million of 6.65% senior notes due 2017 for net proceeds of $494.8 million. The Company used the net proceeds from the 6.65% senior notes to reduce indebtedness under its credit facility.

During May 2006, the Company issued $450.0 million of 6.875% senior notes due 2018 for net proceeds of $447.4 million. The Company used the net proceeds, in part, from the 6.875% senior notes to repurchase $346.2 million of its 6.50% senior notes due 2008 and for general corporate purposes.

During 2006, holders of all of the $100.0 million of 4 3/4% senior convertible notes due 2021 exercised their conversion rights. Associated therewith, the Company paid $79.9 million in cash, issued 2.3 million shares of common stock and recorded a $22.0 million increase to stockholders' equity.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. To enhance the Company's financial flexibility, the Company is also evaluating the merits of executing volumetric production payments, the sale for cash of producing assets to Pioneer Southwest and other alternatives. The Company cannot predict the timing or ultimate outcome of any such actions as they are subject to market conditions, among other factors. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal source of short-term liquidity is cash on hand and unused borrowing capacity under its credit facility. There were $913.0 million of outstanding borrowings under the credit facility as of December 31, 2008. Including $46.0 million of undrawn and outstanding letters of credit under the credit facility, the Company had $541.0 million of unused borrowing capacity as of December 31, 2008. If internal cash flows do not meet the Company's expectations, the Company may further reduce its level of capital expenditures, reduce dividend payments, and/or fund a portion of its capital expenditures using borrowings under its credit facilities, issuances of debt or equity securities or from other sources, such as asset sales. The Company cannot provide any assurance that needed short-term or long-term liquidity will be available on acceptable terms or at all. Although the Company expects that internal cash flows will be adequate to fund capital expenditures and dividend payments, and that available borrowing capacity under the Company's credit facilities will provide adequate liquidity, no assurances can be given that such funding sources will be adequate to meet the Company's future needs. For instance, the amount that the Company may borrow under the credit facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items.

Foreign currency translation. The functional currency of the Company's Canadian subsidiaries was the U.S. dollar ("USD") and the Canadian subsidiaries' financial statements were maintained in Canadian dollars ("CND"). In accordance with GAAP, the net assets of the Canadian subsidiaries were translated into USD-equivalent amounts when they were consolidated into the financial statements of the Company and resulting translation gains and losses were deferred as items of accumulated other comprehensive income or loss in the Company's consolidated stockholders' equity. As a result of modest fluctuations in the USD to CND exchange rates during 2006, the Company recorded other comprehensive income (loss) in accumulated other comprehensive income – cumulative translation adjustment ("AOCI – CTA") in consolidated stockholders equity of $8.1 million. However, during 2007 the CND strengthened significantly against the USD, accordingly, the Company recorded $77.7 million of other comprehensive income in AOCI – CTA. During November 2007, the sale of the Company's common stock in the Canadian subsidiaries was completed, at which time AOCI – CTA was eliminated as a component of the gain on the divestiture of the Canadian assets. See Note V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the divestiture of the Canadian subsidiaries.

Debt ratings. The Company receives debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's rating for the Company is BB+ with a stable outlook. Moody's rating for the Company is Ba1 with a negative outlook. S&P and Moody's consider many factors in determining the Company's ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in the Company's debt ratings could negatively impact the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. As of December 31, 2008, the Company was in compliance with all of its debt covenants.

Book capitalization and current ratio. The Company's net book capitalization at December 31, 2008 was $6.5 billion, consisting of $48.3 million of cash and cash equivalents, debt of $3.0 billion and stockholders' equity of $3.6 billion. The Company's debt to book capitalization decreased to 45 percent at December 31, 2008 from 47 percent at December 31, 2007, primarily due to an increase in stockholders' equity, partially offset by an increase in indebtedness. The Company's ratio of current assets to current liabilities was .70 to 1.00 at December 31, 2008, as compared to .77 to 1.00 at December 31, 2007.

Critical Accounting Estimates

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

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

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

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During 2008, 2007 and 2006, the Company recognized exploration, abandonment, geological and geophysical expense from continuing operations of $235.5 million, 279.3 million and $250.2 million, respectively. During 2007 and 2006, the Company recognized exploration, abandonment, geological and geophysical expense from discontinued operations of $14.4 million and $21.3 million, respectively, under the successful efforts method.

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

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

The Company's proved reserve information included in this Report as of December 31, 2008, 2007 and 2006 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

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

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2008 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the Standardized Measure on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. See “Item 1A. Risk Factors” for additional information regarding estimates of proved reserves.

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

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

Impairment of unproved oil and gas properties. At December 31, 2008, the Company carried unproved property costs of $204.2 million. Management assesses unproved oil and gas properties for impairment on a project-by-project basis. Management's impairment assessments include evaluating the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

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

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

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

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

Assessments of functional currencies. Management determines the functional currencies of the Company's subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The U.S. dollar is the functional currency of all of the Company's current international operations. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

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

31, 2008, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to certain foreign tax jurisdictions.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. This requires the Company to estimate the fair value of the assets and liabilities of the reporting units that have goodwill. There is considerable judgment involved in estimating fair values, particularly in determining the valuation methodologies to utilize, the estimation of proved reserves as described above and the weighting of different valuation methodologies applied. See Notes B and S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

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

Valuations of defined benefit pension and postretirement plans. The Company is the sponsor of certain defined benefit pension and postretirement plans. In accordance with GAAP, the Company is required to estimate the present value of its unfunded pension and accumulated postretirement benefit obligations. Based on those values, the Company records the unfunded obligations of those plans and records ongoing service costs and associated interest expense. The valuation of the Company’s pension and accumulated postretirement benefit obligations requires management assumptions and judgments as to benefit cost inflation factors, mortality rates and discount factors. Changes in these factors may materially change future benefit costs and pension and accumulated postretirement benefit obligations. See “New Accounting Pronouncements” below and Note H of Notes to Consolidated Financial Statements included in “Item 8. Consolidated Financial Statements and Supplementary Data” for additional information regarding the Company’s pension and accumulated postretirement benefit obligations.

Valuation of stock-based compensation. In accordance with SFAS No. 123(R), the Company calculates the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. The Company utilizes (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the stock price on the date of grant for the fair value of restricted stock awards and (c) the Monte Carlo simulation method for the fair value of performance unit awards.

New Accounting Pronouncements

The following discussions provide information about new accounting pronouncements that were issued by the Financial Accounting Standards Board (“FASB”) during 2008:

SFAS 157. In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements (“SFAS 157”). SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. During February 2008, the FASB issued FASB Staff Position No. 157-2 (“FSP FAS 157-2”). FSP FAS 157-2 delayed the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis but no less often than annually. On January 1, 2008, the Company adopted the provisions of SFAS 157 for financial assets and liabilities. See Note E of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the Company’s adoption of SFAS 157. The adoption of the provisions of SFAS 157 that were delayed by FSP FAS 157-2 is not expected to have a material effect on the financial condition or results of operations of the Company.

SFAS 159. In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities” (“SFAS 159”). SFAS 159 permits entities to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The Company adopted the provisions of SFAS 159 on January 1, 2008 and its implementation did not have a material effect on the financial condition or results of operations of the Company.

SFAS 141(R). In December 2007, the FASB issued SFAS No. 141(R), “Business Combinations” (“SFAS 141(R)”). SFAS 141(R) replaces SFAS 141 and provides greater consistency in the accounting and financial reporting of business combinations. SFAS 141(R) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction and any noncontrolling interest in the acquired entity at the acquisition date, measured at their fair values as of the date that the acquirer achieves control over the business acquired. This includes the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the recognition of pre-acquisition contractual and certain non-contractual gain and loss contingencies, the recognition of capitalized research and development costs and the recognition of changes in the acquirer’s income tax valuation allowance and deferred taxes. The provisions of SFAS 141(R) also require that restructuring costs resulting from the business combination that the acquirer expects but is not required to incur and costs incurred to effect the acquisition be recognized separate from the business combination. SFAS 141(R) is effective for fiscal years and interim periods within those fiscal years, beginning on or after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. SFAS 141(R) became effective for the Company on January 1, 2009. The implementation of SFAS 141(R) did not impact the financial condition or results of operations of the Company on the date of adoption.

SFAS 160. In December 2007, the FASB issued SFAS No. 160 “Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB Statement No. 51” (“SFAS 160”). SFAS 160 amends Accounting Research Bulletin (“ARB”) No. 51, “Consolidated Financial Statements,” to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated income statement. SFAS 160 became effective for the Company on January 1, 2009. Although it will not impact the Company’s financial condition or results of operations, it will change the manner in which minority interests in subsidiaries’ net assets and net income (loss) is presented in the Company’s consolidated balance sheets and statements of operations.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133” (“SFAS 161”). SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities by requiring entities to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS 133, “Accounting for Derivative Instruments and Hedging Activities” and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. SFAS 161 became effective for the Company on January 1, 2009 and will only impact future disclosures about the Company’s derivative instruments and hedging activities.

SFAS 162. In May 2008, the FASB issued SFAS No. 162 “The Hierarchy of Generally Accepted Accounting Principles” (“SFAS 162”). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 became effective for the Company on November 15, 2008. The adoption of SFAS 162 did not have a significant impact on the Company’s financial statements.

FSP APB 14-1. In May 2008, the FASB issued FASB Staff Position No. APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)” (“FSP APB 14-1”). FSP APB 14-1 specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity’s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of FSP APB 14-1 will increase the annual interest expense that the Company recognizes on its $480 million of outstanding 2.875% Senior Convertible Notes from an annual yield of approximately 2.875 percent to an annual yield equivalent to a nonconvertible debt borrowing (6.75 percent on the date of issuance). The adoption of FSP APB 14-1 will also result in the reclassification of the estimated issuance date fair value of the 2.875% Senior Convertible Notes conversion privilege from long-term debt to shareholders’ equity in the Company’s consolidated balance sheet. See Note W for information regarding the impact of adopting FSP APB 14-1.

EITF 03-6-1. In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities” (“FSP EITF 03-6-1”), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, “Earnings per Share.” FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP EITF 03-6-1 is not expected to have a material effect on the Company’s net income per share calculations.

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SEC reserve ruling. In December 2008, the SEC released Final Rule, "Modernization of Oil and Gas Reporting" (the "Reserve Ruling"). The Reserve Ruling revises oil and gas reporting disclosures. The Reserve Ruling also permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The Reserve Ruling will also allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Reserve Ruling becomes effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of the provisions of the Reserve Ruling will have on its financial position, results of operations and disclosures.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2008 and 2007, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices.

The fair value of the Company's derivative contracts is determined based on counterparties' estimates and valuation models. The Company did not change its valuation method during 2008. During 2008, the Company was a party to commodity, interest rate and foreign exchange rate swap contracts and commodity collar contracts. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2008:

	Derivative Contract Net Assets (Liabilities) (a)			
	Commodities	Interest Rate	Foreign Exchange Rate	Total
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2007	$ (234,410)	$ —	$ (1,500)	$ (235,910)
Changes in contract fair values (b)	213,478	(10,454)	1,500	204,524
Contract maturities	236,528	551	—	237,079
Contract terminations	(103,310)	—	—	(103,310)
Fair value of contracts outstanding as of December 31, 2008	$ 112,286	$ (9,903)	$ —	$ 102,383

(a) Represents the fair values of open derivative contracts subject to market risk. The Company also had $40.3 million and $69.9 million of obligations under terminated derivatives as of December 31, 2008 and 2007, respectively, for which no market risk exists.
(b) At inception, new derivative contracts entered into by the Company have no intrinsic value.

Effective February 1, 2009, the Company discontinued hedge accounting on all existing commodity derivative instruments, and from that date forward will account for derivative instruments using the mark-to-market accounting method. Therefore, the Company will recognize all future changes in the fair values of its derivative contracts as gains or losses in the earnings of the period in which they occur.

Quantitative Disclosures

Foreign exchange rate sensitivity. During November 2007, the Company invested $131.7 million Canadian dollars ("CND"), representing $132.8 million U.S. dollars ("USD"), in a CND-denominated escrow account associated with the sale of the Company's Canadian assets. During December 2007, the Company entered into foreign exchange rate derivatives to swap $131.7 million CND for $131.0 million USD to be delivered during May 2008. The foreign exchange rate swaps were economic hedges of the CND-denominated escrow account balance; however, uncertainty regarding the matching of cash flow timing between the foreign exchange rate swaps and the liquidation of the CND-denominated escrow account caused the Company not to designate the foreign exchange rate swaps as hedges. The CND-denominated escrow account was liquidated during January 2008 for $129.0 million USD, at which time the foreign exchange rate swaps were terminated at a gain of $1.8 million USD. Subsequent to these transactions, the Company has no remaining material foreign exchange rate risk associated with financial instruments.

Interest rate sensitivity. The following tables provide information about other financial instruments to which the Company was a party as of December 31, 2008 and 2007 that were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2008 and 2007. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 17, 2009.

Interest Rate Sensitivity

Debt Obligations as of December 31, 2008

	Year Ending December 31, 2009	2010	2011	2012	2013	Thereafter	Total	Liability Fair Value December 31, 2008
	(dollars in thousands)							
Total Debt:								
Fixed rate principal maturities (a)	$ —	$ —	$ —	$ 6,110	$ 480,000	$ 1,639,985	$ 2,126,095	$ 1,429,161
Weighted average interest rate	5.74 %	5.74 %	5.74 %	5.73 %	5.74 %	6.83 %		
Variable rate principal maturities	$ —	$ —	$ —	$ 913,000	$ —	$—	$ 913,000	$ 868,597
Weighted average interest rate	2.10 %	2.64 %	3.45 %	3.92 %				
Interest Rate Swaps: (b)								
Notional debt amount	400,000	227,222	25,000					$ 9,903
Fixed rate payable (%)	2.87 %	2.97 %	3.00 %					
Variable rate receivable (%)	1.35 %	1.89 %	2.70 %					

(a) Represents maturities of principal amounts excluding (i) debt issuance discounts and premiums and (ii) deferred fair value hedge gains and losses.

(b) During January 2008, the Company entered into $400 million notional amount of floating-for-fixed interest rate swaps to hedge a portion of the interest rate risk associated with variable rate indebtedness at a fixed weighted average annual interest rate of 2.87 percent, excluding any applicable margins. The interest rate swaps mature during February 2010 ($200 million notional amount) and 2011 ($200 million notional amount).

Interest Rate Sensitivity

Debt Obligations as of December 31, 2007

	Year Ending December 31, 2008	2009	2010	2011	2012	Thereafter	Total	Liability Fair Value December 31, 2007
	(dollars in thousands)							
Total Debt:								
Fixed rate principal maturities (a)	$ 3,777	$ —	$ —	$ —	$ 6,110	$ 1,726,875	$ 1,736,762	$ 1,537,630
Weighted average interest rate	6.55 %	6.55 %	6.55 %	6.55 %	6.55 %	6.76 %		
Variable rate principal maturities	$ —	$ —	$ —	$ —	$ 1,113,000	$—	$ 1,113,000	$ 1,113,000
	3.51 %	3.91 %	4.78 %	5.38 %	5.48 %			

Weighted average
interest rate

____

(a) Represents maturities of principal amounts excluding (i) debt issuance discounts and premiums and (ii) deferred fair value hedge gains and losses.

Commodity price sensitivity. The following tables provide information about the Company's oil and gas derivative financial instruments that were sensitive to changes in oil, NGL and gas prices as of December 31, 2008 and 2007. During the fourth quarter of 2008, market-quoted commodity prices declined significantly from levels reported during the first half of 2008. Although mitigated by the Company's derivative activities, declines in commodity prices will reduce the Pioneer's revenues and internal cash flows. Recent uncertainties in worldwide financial markets may have the effect of reducing liquidity in the financial derivatives market, hampering the Company's ability to enter into derivative contracts under acceptable terms.

Commodity derivative instruments. The Company manages commodity price risk with derivative contracts, such as swap and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor") and maximum ("ceiling") prices for the Company on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price.

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

Oil Price Sensitivity

Derivative Financial Instruments as of December 31, 2008

	Year Ending December 31,			Asset (Liability) Fair Value at December 31,
	2009	**2010**	**2011**	**2008**
				(in thousands)
Oil Hedge Derivatives:				
Average daily notional Bbl volumes (a):				
Swap contracts	2,500	2,000	—	$ 65,293
Weighted average fixed price per Bbl	$ 99.26	$ 98.32	$ —	
Collar contracts	—	—	2,000	$ 33,156
Weighted average ceiling price per Bbl	$ —	$ —	$ 170.00	
Weighted average floor price per Bbl	$ —	$ —	$ 115.00	
Average forward NYMEX oil prices (c)	$ 44.32	$ 53.45	$ 62.26	
Oil Non-Hedge Derivatives (b):				
Average daily notional Bbl volumes (a):				
Swap contracts	11,430	—	—	$ (18,882)
Weighted average fixed price per Bbl	$ 50.31	$ —	$ —	
Average forward NYMEX oil prices (c)	$ 44.32	$ 53.45	$ 62.26	

(a) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for derivative volumes and weighted average prices by calendar quarter.

(b) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into additional non-hedge (i) swap contracts for approximately 10,236 Bbls per day of the Company's 2009 production at an average price of $54.91 per Bbl and (ii) collar contracts for approximately 1,830 Bbls per day of the Company's 2009 production with a floor price of $52.00 per Bbl and a ceiling price of $70.38 per Bbl.

(c) The average forward NYMEX oil prices are based on February 17, 2009 market quotes.

Oil Price Sensitivity

Derivative Financial Instruments as of December 31, 2007

	Year Ending December 31, 2008	2009	2010	Liability Fair Value at December 31, 2007 (in thousands)
Oil Hedge Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	15,250	8,000	4,000	$ 237,071
Weighted average fixed price per Bbl	$ 61.36	$ 71.57	$ 71.46	
Collar contracts	3,000	2,000	—	$ 24,517
Weighted average ceiling price per Bbl	$ 80.80	$ 76.50	$ —	
Weighted average floor price per Bbl	$ 65.00	$ 65.00	$ —	
Average forward NYMEX oil prices (a)	$ 97.22	$ 92.62	$ 90.88	

(a) The average forward NYMEX oil prices are based on February 15, 2008 market quotes.

NGL Price Sensitivity

Derivative Financial Instruments as of December 31, 2008

	Year Ending December 31,		Asset Fair Value at December 31,
	2009	2010	2008
			(in thousands)
NGL Hedge Derivatives (a):			
Average daily notional Bbl volumes: (b)			
Swap contracts	1,250	1,250	$ 18,560
Weighted average fixed price per Bbl	$ 48.99	$ 47.38	
Average forward Mont Belvieu NGL prices (c)	$ 26.68	$ 29.00	

(a) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into non-hedge swap contracts for approximately 1,767 Bbls per day of the Company's 2009 production at an average price of $27.12 per Bbl.

(b) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for derivative volumes and weighted average prices by calendar quarter.

(c) Forward Mont Belvieu NGL prices are not available as formal market quotes. These forward prices represent estimates as of February 13, 2009 provided by third parties who actively trade in the derivatives. Accordingly, these prices are subject to estimates and assumptions.

NGL Price Sensitivity

Derivative Financial Instruments as of December 31, 2007

	Year Ending December 31,			Liability Fair Value at December 31,
	2008	2009	2010	2007
				(in thousands)
NGL Hedge Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	500	500	500	$ 6,211
Weighted average fixed price per Bbl	$ 44.33	$ 41.75	$ 39.63	
Average forward Mont Belvieu NGL prices (a)	$ 55.42	$ 53.19	$ 50.92	

(a) Forward Mont Belvieu NGL prices are not available as formal market quotes. These forward prices represent estimates as of February 15, 2008 provided by third parties who actively trade in the derivatives. Accordingly, these prices are subject to estimates and assumptions.

Gas Price Sensitivity

Derivative Financial Instruments as of December 31, 2008

	Year Ending December 31, 2009	2010	2011	2012	2013	Asset Fair Value at December 31, 2008 (in thousands)
Gas Hedge Derivatives (a):						
Average daily notional MMBtu volumes (b):						
Swap contracts	5,000	5,000	—	—	—	$ 7,933
Weighted average fixed price per MMbtu	$ 8.04	$ 7.73	$ —	$ —	$ —	
Average forward NYMEX gas prices (e)	$ 4.74	$ 6.23	$ —	$ —	$ —	
Gas Non-Hedge Derivatives (c):						
Average daily notional MMBtu volumes (b):						
Swap contracts	52,767	—	—	—	—	$ 2,128
Weighted average fixed price per MMbtu	$ 6.12	$ —	$ —	$ —	$ —	
Average forward NYMEX gas prices (e)	$ 4.74	$ —	$ —	$ —	$ —	
Average daily notional MMBtu volumes (b):						
Basis swap contracts (d)	127,397	80,000	50,000	10,000	10,000	$ 4,098
Weighted average fixed price per MMbtu	$ (1.18)	$ (0.90)	$ (0.83)	$ (0.79)	$ (0.71)	
Average forward basis differential prices (f)	$ (1.05)	$ (0.82)	$ (0.82)	$ (0.76)	$ (0.78)	

(a) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and collar contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(b) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for derivative volumes and weighted average prices by calendar quarter.

(c) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into additional non-hedge (i) swap contracts for approximately 43,452 MMBtu and 80,000 MMBtu, respectively, of the Company's 2009 and 2010 production at an average price of $6.12 per MMBtu and $6.53 per MMBtu, respectively, (ii) basis swap contracts for approximately 48,438 MMBtu, 40,000 MMBtu 10,000 MMBtu and 10,000 MMBtu, respectively, of the Company's 2009-2012 production at an average price differential of $1.12 per MMBtu, $.89 per MMBtu, $.75 per MMBtu and $.76 per MMBtu, respectively.

(d) Represent swaps that fix the basis differentials between Spraberry and Mid-Continent indices at which the Company sells its gas and NYMEX prices.

(e) The average forward NYMEX gas prices are based on February 17, 2009 market quotes.

(f) The average forward basis differential prices are based on February 17, 2009 market quotes for basis differentials between Panhandle Eastern Pipeline and NYMEX-quoted forward prices.

Gas Price Sensitivity

Derivative Financial Instruments as of December 31, 2007

	Year Ending December 31,	Asset Fair Value at December 31,

	2008	2009	2010	2007 (in thousands)
Gas Hedge Derivatives:				
Average daily notional MMBtu volumes:				
Swap contracts	129,167	9,897	2,500	$ 33,389
Weighted average fixed price per MMbtu	$ 7.60	$ 7.85	$ 7.33	
Average forward NYMEX gas prices (a)	$ 9.18	$ 9.36	$ 9.17	

(a) The average forward NYMEX gas prices are based on February 15, 2008 market quotes.

Qualitative Disclosures

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

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

Foreign currency, operations and price risk. International investments represent, and are expected to continue to represent, a portion of the Company's total assets. Pioneer currently has international operations in Tunisia and South Africa, which together represented 15 percent of the Company's 2008 oil and gas revenues from continuing operations. Although Pioneer's primary focus is directed toward onshore North American opportunities, Pioneer continues to identify and selectively evaluate other international opportunities. As a result of such foreign operations, Pioneer's financial results and international operations could be affected by factors such as changes in foreign currency exchange rates, changes in the legal or regulatory environment, weak economic conditions or changes in political or economic climates and other factors. For example:

- local political and economic developments could restrict or increase the cost of Pioneer's foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of Pioneer's foreign operations;
- expropriation of the Company's property could result in loss of revenue, property and equipment;
- civil uprising, riots, terrorist attacks and wars could make it impractical to continue operations, resulting in financial losses;
- compliance with applicable U.S. law could be in conflict with the Company's contractual obligations, the laws of foreign governments or local customs;
- import and export regulations and other foreign laws or policies could result in loss of revenues;
- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict Pioneer's ability to fund foreign operations or may make foreign operations more costly.

Pioneer does not currently maintain political risk insurance. Pioneer evaluates on a country-by-country basis whether obtaining political risk coverage is necessary and may add such insurance in the future if the Company believes it is prudent to do so.

Africa. The Company's producing assets in Africa are in South Africa and Tunisia. The Company views the operating environment in these African nations as stable and the economic stability as good. While the values of the various African nations' currencies fluctuate in relation to the U.S. dollar, the Company believes that any currency risk associated with Pioneer's African operations would not have a material impact on the Company's results of operations given that such operations are closely tied to oil prices, which are denominated in U.S. dollars.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC

ACCOUNTING FIRM

The Board of Directors and Stockholders of

Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pioneer Natural Resources Company at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note P to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109," effective January 1, 2007. As discussed in Note H to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pioneer Natural Resources Company's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2009 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas

February 24, 2009

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31,	
	2008	**2007**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 48,337	$ 12,171
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $22,464 and $7,657 as of December 31, 2008 and 2007, respectively	206,794	283,249
Due from affiliates	759	583
Income taxes receivable	60,573	40,046
Inventories	76,901	97,619
Prepaid expenses	12,464	9,378
Deferred income taxes	6,510	108,073
Other current assets:		
Derivatives	59,622	33,970
Other, net of allowance for doubtful accounts of $5,491 as of December 31, 2008	14,951	179,966
Total current assets	486,911	765,055
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	10,167,220	8,973,634
Unproved properties	204,183	277,479
Accumulated depletion, depreciation and amortization	(2,511,401)	(2,028,472)
Total property, plant and equipment	7,860,002	7,222,641
Deferred income taxes	553	10,263
Goodwill	310,563	310,870
Other property and equipment, net	161,266	152,990
Other assets:		
Derivatives	72,594	684
Other, net of allowance for doubtful accounts of $4,410 and $4,573 as of December 31, 2008 and 2007, respectively	271,289	154,478
	$ 9,163,178	$ 8,616,981

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands, except share data)

	December 31, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 322,688	$ 350,782
Due to affiliates	34,284	27,634
Interest payable	43,247	42,020
Income taxes payable	3,618	12,842
Other current liabilities:		
Derivatives	49,561	262,547
Deferred revenue	147,905	158,138
Other	93,694	140,206
Total current liabilities	694,997	994,169
Long-term debt	2,964,047	2,755,491
Derivatives	20,584	77,929
Deferred income taxes	1,477,530	1,229,677
Deferred revenue	177,236	325,142
Minority interest in consolidated subsidiaries	59,226	11,942
Other liabilities	187,409	179,909
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 124,566,963 and 123,389,014 shares issued at December 31, 2008 and 2007, respectively	1,246	1,234
Additional paid-in capital	2,860,208	2,693,257
Treasury stock, at cost: 10,020,502 and 5,661,692 shares at December 31, 2008 and 2007, respectively	(411,659)	(245,601)
Retained earnings	998,829	822,089
Accumulated other comprehensive income (loss):		
Net deferred hedge gains (losses), net of tax	133,525	(228,257)
Total stockholders' equity	3,582,149	3,042,722
Commitments and contingencies		
	$ 9,163,178	$ 8,616,981

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

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PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)

	Year Ended December 31,		
	2008	**2007**	**2006**
Revenues and other income:			
Oil and gas	$ 2,277,350	$ 1,740,851	$ 1,458,940
Interest and other	61,318	91,883	43,498
Loss on disposition of assets, net	(381)	(2,163)	(6,459)
	2,338,287	1,830,571	1,495,979
Costs and expenses:			
Oil and gas production	595,240	420,738	349,066
Depletion, depreciation and amortization	511,846	387,397	314,081
Impairment of oil and gas properties	104,269	26,215	—
Exploration and abandonments	235,530	279,329	250,196
General and administrative	141,823	129,587	116,595
Accretion of discount on asset retirement obligations	8,699	7,028	3,726
Interest	153,577	135,270	107,050
Hurricane activity, net	12,150	61,309	32,000
Minority interest in consolidated subsidiaries' net income (loss)	21,635	(352)	(2,263)
Other	127,065	29,426	34,290
	1,911,834	1,475,947	1,204,741
Income from continuing operations before income taxes	426,453	354,624	291,238
Income tax provision	(205,639)	(112,645)	(141,021)
Income from continuing operations	220,814	241,979	150,217
Income (loss) from discontinued operations, net of tax	(751)	130,749	589,514
Net income	$ 220,063	$ 372,728	$ 739,731
Basic earnings per share:			
Income from continuing operations	$ 1.88	$ 2.01	$ 1.21
Income (loss) from discontinued operations, net of tax	(0.01)	1.09	4.74
Net income	$ 1.87	$ 3.10	$ 5.95
Diluted earnings per share:			
Income from continuing operations	$ 1.86	$ 1.99	$ 1.19
Income (loss) from discontinued operations, net of tax	(0.01)	1.07	4.62
Net income	$ 1.85	$ 3.06	$ 5.81
Weighted average shares outstanding:			
Basic	117,462	120,158	124,359
Diluted	118,645	121,659	127,608

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands, except dividends per share)

							Accumulated Other Comprehensive Income (Loss)		
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compensation	Retained Earnings (Deficit)	Net Deferred Hedge Losses, Net of Tax	Cumulative Translation Adjustment	Total Stockholders' Equity
Balance as of December 31, 2005	126,832	$ 1,452	$ 3,775,812	$ (882,382)	$ (45,827)	$ (184,320)	$ (506,636)	$ 59,003	$ 2,217,102
Dividends declared ($.25 per share)	—	—	—	—	—	(31,726)	—	—	(31,726)
Conversion of senior notes	2,327	—	(85,023)	107,023	—	—	—	—	22,000
Exercise of long-term incentive plan stock options and employee stock purchases	860	—	4,010	39,568	—	(26,197)	—	—	17,381
Purchase of treasury stock	(8,902)	—	—	(348,945)	—	—	—	—	(348,945)
Tax benefits related to stock-based compensation	—	—	4,247	—	—	—	—	—	4,247
Compensation costs:									
Adoption of SFAS 123(R)	—	—	(45,827)	—	45,827	—	—	—	—
Compensation awards	386	4	(4)	—	—	—	—	—	—
Compensation costs included in net income	—	—	32,065	—	—	—	—	—	32,065
Net income	—	—	—	—	—	739,731	—	—	739,731
Retirement of shares	—	(229)	(1,031,233)	1,031,462	—	—	—	—	—
Other comprehensive income (loss):									
Deferred hedging activity, net of tax:									
Net deferred hedge gains	—	—	—	—	—	—	118,139	—	118,139
Net hedge losses included in continuing operations	—	—	—	—	—	—	96,530	—	96,530
Net hedge losses included in discontinued operations	—	—	—	—	—	—	124,747	—	124,747
Deferred translation adjustment loss	—	—	—	—	—	—	—	(6,600)	(6,600)
Balance as of December 31, 2006	121,503	$ 1,227	$ 2,654,047	$ (53,274)	$ —	$ 497,488	$ (167,220)	$ 52,403	$ 2,984,671
Dividends declared ($0.17 per share)	—	—	—	—	—	(32,921)	—	—	(32,921)
Exercise of long-term incentive plan stock options and employee stock purchases	671	—	—	29,097	—	(15,206)	—	—	13,891
Purchase of treasury stock	(5,150)	—	—	(221,424)	—	—	—	—	(221,424)
Tax benefits related to stock-based compensation	—	—	3,908	—	—	—	—	—	3,908
Compensation costs:									
Compensation awards	703	7	(7)	—	—	—	—	—	—
Compensation costs included in net income	—	—	35,309	—	—	—	—	—	35,309
Net income	—	—	—	—	—	372,728	—	—	372,728
Other comprehensive income (loss):									
Deferred hedging activity, net of tax:									

Net deferred hedge losses	—	—	—	—	—	—	(94,330)	—	(94,330)
Net hedge losses include din continuing operations	—	—	—	—	—	—	52,686	—	52,686
Net hedge gains included in discontinued operations	—	—	—	—	—	—	(19,393)	—	(19,393)
Translation adjustment:									
Deferred translation adjustment gain	—	—	—	—	—	—	—	77,744	77,744
Net gain included in discontinued operations	—	—	—	—	—	—	—	(130,147)	(130,147)
Balance as of December 31, 2007	117,727	$ 1,234	$ 2,693,257	$ (245,601)	$ —	$ 822,089	$ (228,257)	$ —	$ 3,042,722

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands, except dividends per share)

	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Stockholders' Equity
Balance as of December 31, 2007	117,727	$1,234	$2,693,257	$(245,601)	$822,089	$(228,257)	$3,042,722
Dividends declared (0.30 per share)	—	—	—	—	(35,952)	—	(35,952)
Exercise of long-term incentive plan stock options and employee stock purchases	355	—	—	15,439	(7,371)	—	8,068
Purchase of treasury stock	(4,714)	—	—	(181,497)	—	—	(181,497)
Tax benefits related to stock-based compensation	—	—	367	—	—	—	367
Compensation costs:							
Vested compensation awards	1,178	12	(12)	—	—	—	—
Compensation costs included in net income	—	—	33,970	—	—	—	33,970
Gain on sale of Pioneer Southwest common units	—	—	132,626	—	—	—	132,626
Net income	—	—	—	—	220,063	—	220,063
Other comprehensive income:							
Deferred hedging activity, net of tax:							
Hedge fair value changes, net	—	—	—	—	—	138,513	138,513
Net hedge losses included in continuing operations	—	—	—	—	—	223,269	223,269
Balance as of December 31, 2008	114,546	$1,246	$2,860,208	$(411,659)	$998,829	$133,525	$3,582,149

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2008	**2007**	**2006**
Cash flows from operating activities:			
Net income	$ 220,063	$ 372,728	$ 739,731
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	511,846	387,397	314,081
Impairment of oil and gas properties	104,269	26,215	—
Exploration expenses, including dry holes	131,043	171,751	140,135
Hurricane activity	9,000	66,000	75,000
Deferred income taxes	156,948	123,819	161,761
Loss on disposition of assets, net	381	2,163	6,459
(Gain) loss on extinguishment of debt	(23,248)	—	8,076
Accretion of discount on asset retirement obligations	8,699	7,028	3,726
Discontinued operations	459	(76,423)	(489,959)
Interest expense	15,284	17,049	11,042
Minority interest in consolidated subsidiaries’ net income (loss)	21,635	(352)	(2,263)
Commodity hedge related activity	45,166	12,084	(8,443)
Amortization of stock-based compensation	33,970	35,309	32,065
Amortization of deferred revenue	(158,139)	(181,231)	(190,327)
Other noncash items	60,875	3,182	14,486
Change in operating assets and liabilities, net of effects from acquisitions and dispositions:			
Accounts receivable, net	45,446	(96,691)	121,360
Income taxes receivable	(20,528)	(15,378)	(23,495)
Inventories	(82,403)	(10,901)	(48,060)
Prepaid expenses	(3,405)	656	4,808
Other current assets, net	(11,745)	(2,946)	(42,484)
Accounts payable	65,644	30,122	(36,085)
Interest payable	1,227	11,012	(6,500)
Income taxes payable	(9,225)	(23)	(3,695)
Other current liabilities	(98,034)	(107,255)	(26,591)
Net cash provided by operating activities	1,025,228	775,315	754,828
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	292,920	420,874	1,644,829
Additions to oil and gas properties	(1,403,272)	(2,067,648)	(1,403,879)
Additions to other assets and other property and equipment, net	(41,058)	(136,218)	(95,435)
Net cash provided by (used in) investing activities	(1,151,410)	(1,782,992)	145,515
Cash flows from financing activities:			
Borrowings under long-term debt	1,032,998	2,030,000	1,426,490
Principal payments on long-term debt	(807,239)	(778,630)	(1,981,164)

Proceeds from issuance of partnership common units, net of issuance costs	165,978	—	—
Borrowings (payments) of other liabilities	(8,033)	768	610
Exercise of long-term incentive plan stock options and employee stock purchases	8,068	13,891	17,381
Purchase of treasury stock	(181,497)	(221,424)	(348,945)
Excess tax benefits from share-based payment arrangements	367	3,828	5,989
Payment of financing fees	(12,377)	(4,310)	(2,178)
Dividends paid	(35,917)	(32,804)	(31,726)
Net cash provided by (used in) financing activities	162,348	1,011,319	(913,543)
Net increase (decrease) in cash and cash equivalents	36,166	3,642	(13,200)
Effect of exchange rate changes on cash and cash equivalents	—	1,496	1,431
Cash and cash equivalents, beginning of year	12,171	7,033	18,802
Cash and cash equivalents, end of year	$ 48,337	$ 12,171	$ 7,033

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2008	2007	2006
Net income	$ 220,063	$ 372,728	$ 739,731
Other comprehensive income:			
Net hedge activity, net of tax:			
Hedge fair value changes, net	138,513	(94,330)	118,139
Net hedge losses included in continuing operations	223,269	52,686	96,530
Net hedge (gains) losses included in discontinued operations	—	(19,393)	124,747
Translation adjustment:			
Deferred translation adjustment gain (loss)	—	77,744	(6,600)
Net gain included in discontinued operations	—	(130,147)	—
Other comprehensive income (loss)	361,782	(113,440)	332,816
Comprehensive income	$ 581,845	$ 259,288	$ 1,072,547

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

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2008, 2007 and 2006

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company ("Pioneer" or the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company with continuing operations in the United States, South Africa and Tunisia.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. Statement of Financial Accounting Standards Board ("FASB") Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities" ("FIN46(R)") requires that the Company's consolidated financial statements also include the accounts of variable interest entities ("VIEs") in which Pioneer holds a variable interest that will absorb a majority of the entities' expected losses, receive a majority of the entities' expected residual returns, or both. In accordance therewith, the accompanying consolidated financial statements include the accounts of PNR Holdings LLC as of and for the year ended December 31, 2007 (see "Oil and gas properties," below for additional information regarding PNR Holdings LLC). The Company proportionately consolidates less than 100 percent-owned affiliate partnerships, for which certain of its wholly-owned subsidiaries serve as general partners, involved in oil and gas producing activities in accordance with Emerging Issues Task Force ("EITF") Abstract Issue No. 00-1, "Investor Balance Sheet and Income Statement Display under the Equity Method for Investments in Certain Partnerships and Other Ventures." The Company owns less than a 31 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Minority interests in consolidated subsidiaries. On May 6, 2008, Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest"), a subsidiary of the Company, completed its initial public offering, at a per-unit offering price of $19.00, of 9,487,500 common units, representing a 31.6 percent limited partner interest in Pioneer Southwest. Associated therewith, the Company recognized $166.0 million of net proceeds from the issuance of Pioneer Southwest common units in net cash provided by financing activities in the accompanying consolidated statement of cash flows for the year ended December 31, 2008 and recognized a $132.6 million noncash gain on the sale of Pioneer Southwest common units in the accompanying consolidated statement of stockholders' equity for the year ended December 31, 2008. Pioneer Southwest owns interests in certain oil and gas properties previously owned by the Company in the Spraberry field in the Permian Basin of West Texas. The Company owns a 0.1 percent general partner interest and a 68.3 percent limited partner interest in Pioneer Southwest. The financial position, results of operations, and cash flows of Pioneer Southwest are consolidated with those of the Company. The Company elected to account for gains on Pioneer Southwest's issuance of common units as equity transactions as permitted by Staff Accounting Bulletin ("SAB") Topic 5H, "Accounting for Sales of Stock by a Subsidiary."

In addition to Pioneer Southwest, the Company owns the majority interests in certain subsidiaries with operations in the United States and owned the majority interest in a subsidiary with operations in Nigeria, which was disposed of in 2007. Minority interest in the net assets of consolidated subsidiaries totaled $59.2 million and $11.9 million as of December 31, 2008 and 2007, respectively, which are included as liabilities in the accompanying consolidated balance sheets. Minority interest in the net income (loss) of the Company's consolidated subsidiaries totaled $21.6 million, $(352) thousand and $(2.3) million for the years ending December 31, 2008, 2007 and 2006, respectively, which are included in the accompanying consolidated statements of operations.

Discontinued operations. During 2007 and 2006, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006
Canada	Canadian assets	November 2007

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2008, 2007 and 2006

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"), the Company has reflected the results of operations of the above divestitures as discontinued operations, rather than as a component of continuing operations. See Note V for additional information regarding discontinued operations.

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

Cash equivalents. Cash and cash equivalents include cash on hand and depository accounts held by banks.

Accounts and notes receivable. As of December 31, 2008 and 2007, the Company had accounts receivable – trade, net of allowances for bad debts, of $206.8 million and 283.2 million, respectively, and notes receivable, net of allowances for bad debts, of $11.3 million and $17.7 million, respectively. The Company's accounts receivable – trade are primarily comprised of oil and gas sales receivable, joint operations receivables and other receivables for which the Company does not require collateral security. The Company's notes receivable are primarily comprised of notes collateralized by drilling rigs and long-lived assets.

As of December 31, 2008 and December 31, 2007, the Company's allowances for doubtful accounts totaled $32.4 million and $12.2 million, respectively. In accordance with SFAS No. 5, "Accounting for Contingencies," the Company establishes allowances for bad debts equal to the estimable portions of accounts and notes receivables for which failure to collect is considered probable. The Company estimates the portions of joint interest receivables for which failure to collect is probable based on percentages of joint interest receivables that are past due. The Company estimates the portions of other receivables for which failure to collect is probable based on the relevant facts and circumstances surrounding the receivable. Allowances for doubtful accounts are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable.

	Year Ended December 31, 2008

	(in thousands)
Beginning allowance for doubtful accounts	$ 12,230
Amount charged to costs and expenses (a)	30,119
Write off of uncollectible accounts	(9,984)
Ending allowance for doubtful accounts	$ 32,365

(a) Includes a $19.6 million bad debt charge related to the SemGroup bankruptcy. See Note I for additional information regarding this receivable.

Investments. Investments in unaffiliated equity securities that have a readily determinable fair value are classified as "trading securities" if management's current intent is to hold them for the near term; otherwise, they are accounted for as "available-for-sale" securities. The Company reevaluates the classification of investments in unaffiliated equity securities at each balance sheet date. The carrying value of trading securities and available-for-sale securities are adjusted to fair value as of each balance sheet date.

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Unrealized holding gains are recognized for trading securities in interest and other income, and unrealized holding losses are recognized in other expense during the periods in which changes in fair value occur.

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company had no investments in available-for-sale securities as of December 31, 2008 or 2007.

Investments in unaffiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company had no significant equity security investments that did not have a readily determinable fair value as of December 31, 2008 or 2007.

Inventories. Inventories were comprised of $158.7 million and $94.3 million of materials and supplies and $8.4 million and $3.3 million of commodities as of December 31, 2008 and 2007, respectively. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a first-in, first-out cost basis. "Market", in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. Any valuation reserve allowances of materials and supplies inventory are recorded as reductions to the carrying values of the materials and supply inventories in the Company's consolidated balance sheets and as losses on disposition of assets in the accompanying consolidated statements of operations. As of December 31, 2008 and 2007, the Company's materials and supplies inventory was net of $4.7 million and $1.1 million, respectively, of valuation reserve allowances. The Company estimates that approximately $90.2 million of its December 31, 2008 materials and supplies inventory will not be utilized during 2009 due to declines in budgeted drilling activities. Accordingly, those inventory values have been classified as other noncurrent assets in the accompanying consolidated balance sheet as of December 31, 2008.

Commodities inventories are carried at the lower of average cost or market, on a first-in, first-out basis. The Company's commodities inventories consist of oil and natural gas liquids ("NGLs") held in storage. Any valuation allowances of commodities inventories are recorded as reductions to the carrying values of the commodities inventories included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations. As of December 31, 2008, the Company's commodities inventories were net of $159 thousand of valuation allowances.

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

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

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

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

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to

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accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note D for additional information regarding the Company's suspended exploratory well costs.

The Company owns interests in four natural gas processing plants and thirteen treating facilities. The Company operates two of the gas processing plants and twelve of the treating facilities. The Company's ownership interests in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. Third party revenues generated from the plant and treating facilities for the three years ended December 31, 2008, 2007 and 2006 were $39.4 million, $30.3 million and $28.6 million, respectively. Third party expenses attributable to the plants and treating facilities for the same respective periods were $14.4 million, $12.1 million and $8.4 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

Capitalized costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is completed and proved reserves are established or, if unsuccessful, impairment is determined.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion, depreciation and amortization. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base.

In accordance with SFAS No. 144, the Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. Estimates of the sum of expected future cash flows requires management to estimate future recoverable proved and risk-adjusted probable and possible reserves, forecasts of future commodity prices, production and capital costs and discount rates. Uncertainties about these future cash flow variables cause impairment estimates to be inherently imprecise. See Note S for additional information regarding the Company's impairment assessments.

Unproved oil and gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of 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 an impairment loss at that time.

During December 2007, PNR Holdings LLC completed acquisitions of proved and unproved oil and gas properties located in the Raton Basin in southeastern Colorado and the Barnett Shale play in North Texas for $352.2 million. The Company caused PNR Holdings LLC to be formed pursuant to an agreement with a third party in anticipation of having the acquisitions treated as part of a tax-deferred, like-kind-exchange with the anticipated sale of oil and gas properties to Pioneer Southwest, a subsidiary of the Company. As of December 31, 2007, the Company controlled PNR Holdings LLC pursuant to a management agreement (the “Management Agreement”) whereby Pioneer Natural Resources USA, Inc. (“PNR USA”), a wholly-owned subsidiary of the Company, provided operating and administrative management of all of PNR Holdings LLC’s properties. PNR Holdings LLC financed the acquisitions with borrowings under a credit agreement (“Holdings Credit Agreement”) entered into

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with PNR USA. Under the terms of the Holdings Credit Agreement and Management Agreement, PNR Holdings LLC was a VIE in which PNR USA received substantially all of the entity's residual returns and absorbed substantially all of the entity's losses. PNR USA's loans under the Holdings Credit Agreement were secured by the property interests acquired by PNR Holdings LLC. General creditors of PNR Holdings LLC may have lacked recourse as a result of PNR USA's secured debtor standing. As of December 31, 2007, PNR Holdings LLC's proved oil and gas properties had a net carrying value of $260.3 million and unproved oil and gas properties with a carrying value of $91.5 million that were included in the accompanying consolidated balance sheet as of December 31, 2007. Outstanding PNR Holdings LLC borrowings of $351.8 million as of December 31, 2007 under the Holdings Credit Agreement were eliminated in consolidation against the associated loans from PNR USA. During 2008, PNR Holdings LLC was acquired by the Company, became a wholly-owned subsidiary and was liquidated.

Goodwill. During 2004, the Company recorded $327.8 million of goodwill associated with a business combination. The goodwill was recorded to the Company's United States reporting unit. In accordance with EITF Abstract Issue No. 00-23, "Issues Related to the Accounting for Stock Compensation under APB Opinion No. 25 and FASB Interpretation No. 44," the Company has reduced goodwill by $17.2 million since the date of the business combination, primarily for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the business combination. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"), goodwill is not amortized to earnings, but is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. If the carrying value of goodwill is determined to be impaired, it is reduced for the impaired value with a corresponding charge to pretax earnings in the period in which it is determined to be impaired. During the third quarter of 2008, the Company performed its annual assessment of impairment of the goodwill and determined that there was no impairment. However, during the second half of 2008, commodity prices and the market capitalization of the Company declined significantly, which the Company considered events that might indicate impairment to the carrying value of goodwill. As a result, the Company reassessed goodwill for impairment as of December 31, 2008, and determined that there was no impairment. See Note S for additional information regarding the Company's impairment assessments.

Other property, plant and equipment, net. Other property, plant and equipment is recorded at cost and primarily consists of items such as heavy equipment and well servicing rigs, furniture and fixtures and leasehold improvements. Depreciation is provided over the estimated useful life of the assets using the straight-line method. At December 31, 2008 and 2007 other property, plant and equipment was net of accumulated depreciation of $190.6 million and $166.6 million, respectively.

Asset retirement obligations. The Company accounts for asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Under the provisions of SFAS 143, asset retirement obligations are generally capitalized as part of the carrying value of the long-lived asset. Conditional asset retirement obligations meet the definition of liabilities and are recognized when incurred if their fair values can be reasonably estimated.

Asset retirement obligation expenditures are classified as cash used in operating activities in the accompanying consolidated statements of cash flows.

Derivatives and hedging. The Company follows the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income. Under the provisions of SFAS 133, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative hedge contract or by effectiveness

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assessments using statistical measurements. The Company's policy is to assess hedge effectiveness at the end of each calendar quarter.

Under the provisions of SFAS 133, changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities, or firm commitments through net income. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in accumulated other comprehensive income (loss) - net deferred hedge gains (losses), net of tax ("AOCI - Hedging") in the stockholders' equity section of the Company's consolidated balance sheets until such time as the hedged items are recognized in net income. Ineffective portions of a derivative instrument's change in fair value are immediately recognized in earnings.

Through November 2008, the Company had elected to designate the majority of its commodity derivative instruments as cash flow hedges. During December 2008, the Company began entering into commodity derivative contracts that were not designated as hedges under SFAS 133. The changes in the fair value of these instruments are being recognized as gains or losses in the earnings of the period in which they occur. Effective January 31, 2009, the Company discontinued hedge accounting on all existing hedge contracts. Net deferred hedge gains deferred in AOCI – Hedging associated with these contracts as of January 31, 2009 will be reclassified to earnings during the same periods in which the hedged transactions are recognized in the Company's earnings.

In accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" ("FIN 39"), the Company classifies the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net derivative assets or net derivative liabilities, whichever the case may be.

See Note J for a description of the specific types of derivative transactions in which the Company participates.

Environmental. The Company's environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability is fixed or reliably determinable.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

Revenue recognition. The Company does not recognize revenues until they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectibility is reasonably assured.

The Company uses the entitlements method of accounting for oil, NGL and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying consolidated balance sheets.

The Company had no material oil entitlement assets or NGL entitlement assets or liabilities as of December 31, 2008 or 2007. The following table presents the Company's oil entitlement liabilities and gas entitlement assets and liabilities with their associated volumes as of December 31, 2008 and 2007:

	December 31,			
	2008		2007	
	Amount	Volume	Amount	Volume
	(dollars in millions)			
Oil entitlement liabilities (volumes in MBbls)	$ 0.5	13	$ 12.6	129
Gas entitlement assets (volumes in MMcf)	$ 8.9	3,227	$ 8.8	3,291
Gas entitlement liabilities (volumes in MMcf)	$ 6.1	1,288	$ 4.3	1,127

Stock-based compensation. On January 1, 2006, the Company adopted SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") to account for stock-based compensation. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant, is being recognized in the Company's financial statements over the vesting period. The Company utilizes (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the stock price on the date of grant for the fair value of restricted stock awards and (c) the Monte Carlo simulation method for the fair value of performance unit awards.

Additionally, under the provisions of SFAS 123(R), deferred compensation recorded under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") related to equity-based awards was required to be eliminated against the appropriate equity accounts. As a result, upon adoption of SFAS 123(R), the Company eliminated $45.8 million of deferred compensation cost in stockholders' equity and reduced a like amount of additional paid-in capital in the accompanying consolidated balance sheets.

For the years ended December 31, 2008, 2007 and 2006, the Company recorded $34.0 million, $35.3 million and 32.1 million of compensation costs for all stock-based plans, respectively, including compensation costs of $422 thousand, $606 thousand and $669 thousand, respectively, associated with the Company's Employee Stock Purchase Plan (the "ESPP"), which is a compensatory plan under the provisions of SFAS 123(R). The impact to the Company's net income of the year ended December 31, 2006 of adopting SFAS 123(R) was $1.6 million, or less than $.02 per diluted share, including the $669 thousand of ESPP compensation expense recorded in that year.

Pursuant to the provisions of SFAS 123(R), the Company's issued shares, as reflected in the accompanying consolidated balance sheets and consolidated statements of stockholders' equity at December 31, 2008 and 2007, do not include 1,078,267 shares and 1,960,475 shares, respectively, of unvested voting shares awarded under stock-based compensation plans.

Foreign currency translation. The U.S. dollar is the functional currency for all of the Company's current international operations. Accordingly, monetary assets and liabilities denominated in a foreign currency are remeasured to U.S. dollars at the exchange rate in effect at the end of each reporting period; revenues and costs and expenses denominated in a foreign currency are remeasured at the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from remeasuring foreign currency denominated balances into U.S. dollars are recorded in other income or other expense, respectively. Nonmonetary assets and liabilities denominated in a foreign currency are remeasured at the historic exchange rates that were in effect when the assets or liabilities were acquired or incurred.

Prior to their sale, the functional currency of the Company's Canadian operations was the Canadian dollar. The financial statements of the Company's Canadian subsidiaries were translated to U.S. dollars as follows: all assets and liabilities were translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses were translated using the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from translating Canadian dollar denominated balances were recorded in the accompanying consolidated statements of stockholders' equity for the period through accumulated other comprehensive income (loss) - cumulative translation adjustment ("AOCI-CTA").

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During November 2007, the Company completed the divestiture of its Canadian subsidiaries. As such, the net cumulative translation adjustment previously deferred in AOCI-CTA was recognized as part of the gain on sale of the Canadian subsidiaries. See Note V for a discussion of the Company's discontinued operations, which include the historical operating results of its Canadian subsidiaries.

The following table presents the exchange rates used to translate the financial statements of the Company's Canadian subsidiaries in the preparation of the consolidated financial statements for the years ended December 31, 2007 and 2006:

	Years Ended December 31,	
	2007	2006
U.S. Dollar from Canadian Dollar – statements of operations	.9365	.8817

New accounting pronouncements. The following discussions provide information about new accounting pronouncements that were issued by FASB during 2008, 2007 and 2006:

SFAS 157. In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. During February 2008, the FASB issued FASB Staff Position No. 157-2, "FSP FAS 157-2" ("FSP FAS 157-2"). FSP FAS 157-2 delayed the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, but no less often than annually. On January 1, 2008, the Company adopted the provisions of SFAS 157 for financial assets and liabilities. See Note E for additional information regarding the Company's adoption of SFAS 157. The adoption of the provisions of SFAS 157 that were delayed by FSP FAS 157-2 is not expected to have a material effect on the financial condition or results of operations of the Company.

SFAS 159. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 permits entities to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The Company adopted the provisions of SFAS 159 on January 1, 2008 and its implementation did not have a material effect on the financial condition or results of operations of the Company.

SFAS 141(R). In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS 141(R)"). SFAS 141(R) replaces SFAS 141 and provides greater consistency in the accounting and financial reporting of business combinations. SFAS 141(R) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction and any noncontrolling interest in the acquired entity at the acquisition date, measured at their fair values as of the date that the acquirer achieves control over the business acquired. This includes the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the recognition of pre-acquisition contractual and certain non-contractual gain and loss contingencies, the recognition of capitalized research and development costs and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. The provisions of SFAS 141(R) also require that restructuring costs resulting from the business combination that the acquirer expects but is not required to incur and costs incurred to effect the acquisition be recognized separate from the business combination. SFAS 141(R) is effective for fiscal years and interim periods within those fiscal years, beginning on or after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. SFAS 141(R) became effective for the Company on January 1, 2009. The implementation of SFAS 141(R) did not materially impact the financial condition or results of operations of the Company on the date of adoption.

SFAS 160. In December 2007, the FASB issued SFAS No. 160 "Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB Statement No. 51" ("SFAS 160"). SFAS 160 amends Accounting Research Bulletin ("ARB") No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160

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clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated income statement. SFAS 160 became effective for the Company on January 1, 2009. Although it will not impact the Company's financial condition or results of operations, it will change the manner in which minority interests in subsidiaries' net assets and net income (loss) is presented in the Company's consolidated balance sheets and statements of operations.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" ("SFAS 161"). SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities by requiring entities to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 became effective for the Company on January 1, 2009 and will only impact future disclosures about the Company's derivative instruments and hedging activities.

SFAS 162. In May 2008, the FASB issued SFAS No. 162 "The Hierarchy of Generally Accepted Accounting Principles" ("SFAS 162"). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 became effective for the Company on November 15, 2008. The adoption of SFAS 162 did not have a significant impact on the Company's consolidated financial statements.

FSP APB 14-1. In May 2008, the FASB issued FASB Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)" ("FSP APB 14-1"). FSP APB 14-1 specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of FSP APB 14-1 will increase the annual interest expense that the Company recognizes on its $480 million of outstanding 2.875% convertible senior notes due January 15, 2038 (the "2.875% Senior Convertible Notes") from an annual yield of approximately 2.875 percent to an annual yield equivalent to a nonconvertible debt borrowing (6.75 percent on the date of issuance). The adoption of FSP APB 14-1 on January 1, 2009 will also result in the reclassification of the estimated issuance date fair value of the 2.875% Senior Convertible Notes conversion privilege from long-term debt to shareholders' equity in the Company's consolidated balance sheet. See Note W for information regarding the impact of adopting FSP APB 14-1.

EITF 03-6-1. In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" ("FSP EITF 03-6-1"), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, "Earnings per Share." FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP EITF 03-6-1 is not expected to have a material effect on the Company's net income per share calculations.

SEC reserve ruling. In December 2008, the SEC released Final Rule, "Modernization of Oil and Gas Reporting" (the "Reserve Ruling"). The Reserve Ruling revises oil and gas reporting disclosures. The Reserve Ruling also permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The Reserve Ruling will also allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii)

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report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Reserve Ruling becomes effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of the provisions of the Reserve Ruling will have on its financial position, results of operations and disclosures.

NOTE C. Proved Property Acquisitions

During the years ended December 31, 2008, 2007 and 2006, the Company expended approximately $87.5 million, $331.6 million and $78.3 million, respectively, to acquire working interests in proved oil and gas properties. During 2008, 2007 and 2006, the Company's proved oil and gas property acquisitions were principally in the United States. During 2008, the Company's proved acquisitions primarily comprised property interests in the South Texas Edwards Trend, the West Texas Permian Basin and the Barnett Shale play in North Texas. During 2007, the Company's proved acquisitions primarily comprised property interests in the West Texas Permian Basin, the Colorado Raton Basin, the Barnett Shale play in North Texas and onshore Gulf Coast. During 2006, the Company's proved acquisitions primarily comprised property interests in the West Texas Permian Basin, onshore Gulf Coast and Alaska.

NOTE D. Exploratory Well Costs

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in proved properties in the consolidated balance sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands)		
Beginning capitalized exploratory well costs	$ 130,630	$ 265,053	$ 198,291
Additions to exploratory well costs pending the determination of proved reserves	403,692	434,321	451,109
Reclassification due to determination of proved reserves	(321,436)	(388,630)	(193,480)
Disposition of wells sold	—	(20,369)	(52,628)

Exploratory well costs charged to expense (a)	(88,872)	(159,745)	(138,239)
Ending capitalized exploratory well costs	$124,014	$130,630	$265,053

(a) Includes exploratory well costs of discontinued operations of $4.4 million and $11.1 million in 2007 and 2006, respectively.

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The following table provides an aging as of December 31, 2008, 2007 and 2006 of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the date the drilling was completed:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands, except project counts)		
Capitalized exploratory well costs that have been suspended:			
One year or less	$ 54,423	$ 76,237	$ 126,749
More than one year	69,591	54,393	138,304
	$ 124,014	$ 130,630	$ 265,053
Number of wells with exploratory well costs that have been suspended for a period greater than one year	4	8	14

The following table provides the capitalized costs of exploration projects that have been suspended for more than one year as of December 31, 2008:

	Year Costs Incurred			
	Total	**2008**	**2007**	**2006**
	(in thousands)			
United States:				
Cosmopolitan Unit	$ 58,661	$ 6,344	$ 51,488	$ 829
Other	2,840	(134)	48	2,926
Other foreign	8,090	(289)	4,434	3,945
Total	$ 69,591	$ 5,921	$ 55,970	$ 7,700

The following discussion describes the history of each significant suspended exploratory project as of December 31, 2008:

Cosmopolitan Unit. The Company owns a 100 percent working interest in, and is the operator of, the Cosmopolitan Unit in the Cook Inlet of Alaska. 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. As a result, the Company began permitting and facilities planning during 2008 to further evaluate the unit's resource potential. During 2009, the Company plans to continue with permitting, progress engineering studies and develop plans for a second well to be drilled in 2010 to further delineate the extent of the unit's resource potential.

NOTE E. Disclosures About Fair Value Measurements

Effective January 1, 2008, the Company adopted the provisions of SFAS 157 for financial assets and liabilities measured at fair value. SFAS 157 retains the exchange price notion in the definition of fair value but clarifies that the exchange price is the price in an orderly transaction between market participants to sell an asset or transfer a liability in the principal or most advantageous market in which the reporting company would transact for the asset or liability.

The SFAS 157 valuation framework is based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

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- Level 1 – quoted prices for identical assets or liabilities in active markets.
- Level 2 – quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability (e.g. interest rates); and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 – unobservable inputs for the asset or liability.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following table presents the Company's financial assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2008, for each of the fair value hierarchy levels:

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Fair Value at December 31, 2008**
	(in thousands)			
Assets:				
Trading securities	$ 301	$ 55	$ —	$ 356
Commodity price derivatives	—	112,608	18,560	131,168
Deferred compensation plan assets	18,276	—	—	18,276
Notes receivable due 2008 to 2011	—	—	11,258	11,258
Total assets	$ 18,577	$ 112,663	$ 29,818	$ 161,058
Liabilities:				
Commodity price derivatives	$ —	$ 18,882	$ —	$ 18,882
Interest rate derivatives	—	9,903	—	9,903
Credit facility	—	868,597	—	868,597
2.875% senior convertible notes due 2038	345,600	—	—	345,600
5.875% senior notes due 2012	5,233	—	—	5,233
5.875% senior notes due 2016	301,583	—	—	301,583
6.65% senior notes due 2017	339,570	—	—	339,570
6.875% senior notes due 2018	292,175	—	—	292,175

7.20% senior notes due 2028	145,000	—	—	145,000
Total liabilities	$ 1,429,161	$ 897,382	$ —	$ 2,326,543

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The following table presents the changes in the fair values of the Company's net commodity price derivative assets and notes receivable classified as Level 3 in the fair value hierarchy:

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	Year Ended December 31, 2008 Commodity Price Derivatives (in thousands)	Notes Receivable	Total
Beginning balance	$ —	$ 16,680	$ 16,680
Total gains (losses):			
Net derivative losses included in earnings (a)	(1,781)	—	(1,781)
Net derivative gains included in other comprehensive income	26,561	—	26,561
Notes receivable valuation allowance included in earnings (b)	—	(5,422)	(5,422)
Transfers into Level 3	(6,220)	—	(6,220)
Ending balance	$ 18,560	$ 11,258	$ 29,818

(a) The hedge-effective portions of realized gains and losses on commodity price derivatives are included in oil and gas revenues, or in other income or other expense for non-hedge derivatives or ineffective portions of realized gains and losses, in the accompanying consolidated statements of operations.

(b) The valuation allowance associated with the Company's notes receivable is included in other expense in the accompanying consolidated statements of operations.

The following table presents the carrying amounts and fair values of the Company's financial instruments as of December 31, 2008 and 2007:

	December 31, 2008 Carrying Value (in thousands)	Fair Value	2007 Carrying Value	Fair Value
Assets:				
Commodity price derivatives	$ 131,168	$ 131,168	$ 34,487	$ 34,487
Terminated commodity price derivatives	$ 1,048	$ 1,048	$ 168	$ 168
Trading securities	$ 356	$ 356	$ 539	$ 539
Deferred compensation plan assets	$ 18,276	$ 18,276	$ 22,857	$ 22,857
Notes receivable due 2008 to 2011	$ 11,258	$ 11,258	$ 16,680	$ 16,680

Canadian escrow deposit account	$ —	$ —	$ 132,025	$132,025
Liabilities:				
Commodity price derivatives	$ 18,882	$ 18,882	$ 268,897	$268,897
Terminated commodity price derivatives	$ 41,360	$ 41,360	$ 70,080	$70,080
Interest rate derivatives	$ 9,903	$ 9,903	$ —	$—
Foreign exchange rate derivatives	$ —	$ —	$ 1,500	$1,500
Credit facility	$ 913,000	$ 868,597	$ 1,113,000	$1,113,000
2.875% senior convertible notes due 2038	$ 480,000	$ 345,600	$ —	$—
6.50% senior notes due 2008	$ —	$ —	$ 3,776	$3,776
5.875% senior notes due 2012	$ 6,191	$ 5,233	$ 6,213	$5,968
5.875% senior notes due 2016	$ 382,010	$ 301,583	$ 434,442	$458,961
6.65% senior notes due 2017	$ 483,792	$ 339,570	$ 498,534	$452,900
6.875% senior notes due 2018	$ 449,132	$ 292,175	$ 449,605	$403,425
7.20% senior notes due 2028	$ 249,922	$ 145,000	$ 249,921	$212,600

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Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Trading securities and deferred compensation plan assets. The Company's trading securities represent equity securities that are actively traded on major exchanges and, to a lesser extent, trading securities that are not actively traded on major exchanges. The Company's deferred compensation plan assets represent investments in equity and mutual fund securities that are actively traded on major exchanges plus unallocated contributions as of the measurement date. As of December 31, 2008, all significant inputs to these asset exchange values represented Level 1 independent active exchange market price inputs except inputs for trading securities that are not actively traded on major exchanges, which were provided by broker quotes representing Level 2 inputs.

Interest rate derivatives. The Company's interest rate derivative assets represent swap contracts for $400 million notional amount of debt, whereby the Company pays a fixed rate of interest and the counterparty receives a variable LIBOR-based rate. In accordance with FIN 39, the Company classifies derivative assets and liabilities in accordance with master netting agreements with the derivative counterparties. The Company's derivative assets and liabilities are comprised of assets and liabilities due from derivative counterparties that are net derivative creditors or net derivative debtors of the Company as of December 31, 2008. Net derivative asset transfer values are determined, in part, by utilization of the derivative counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined, in part, by utilization of the Company's credit-adjusted risk-free rate curve. The credit-adjusted risk-free rates are based on an independent market-quoted credit default swap rate curve for the Company's or the counterparties' debt plus the United States Treasury Bill yield curve as of December 31, 2008. The net derivative asset values attributable to the Company's interest rate derivative contracts as of December 31, 2008 are based on (i) the contracted notional amounts, (ii) forward active market-quoted LIBOR rate yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative asset measurements represent Level 2 inputs in the hierarchy priority.

Commodity price derivatives. The Company's commodity price derivatives represent oil, NGL and gas swap and collar contracts. The Company's commodity price measurements for oil and gas derivative contracts represent Level 2 inputs in the hierarchy priority while NGL derivative contracts represent Level 3 inputs in the hierarchy priority.

Oil derivatives. The Company's oil derivatives are swap and collar contracts for notional Bbls of oil at fixed (in the case of swaps contracts) or interval (in the case of collar contracts) NYMEX West Texas Intermediate ("WTI") oil prices. The asset and liability values attributable to the Company's oil derivatives as of December 31, 2008 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil, (iii) the applicable estimated credit-adjusted risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar contracts. The implied rates of volatility inherent in the Company's collar contracts were determined based on implied volatility factors provided by the derivative counterparties, adjusted for estimated volatility skews. The volatility factors are not considered significant to the fair values of the collar contracts since intrinsic and time values are the principal components of the collar values. As of December 31, 2007, the fair value of oil derivatives were estimated from quotes provided by the counterparties to these derivative contracts.

NGL derivatives. The Company's NGL derivatives are swap contracts for notional blended Bbls of Mont Belvieu-posted-price NGLs. The asset and liability values attributable to the Company's NGL derivatives as of December 31, 2008 are based on (i) the contracted notional volumes, (ii) independent broker-supplied forward Mont Belvieu-posted-price quotes and (iii) the applicable credit-adjusted risk-free rate yield curve. As of December 31, 2007, the fair value of NGL derivatives were estimated from quotes provided by the counterparties to these derivative contracts.

Gas derivatives. The Company's gas derivatives are swap contracts for notional MMBtus of gas contracted at various posted price indexes, including NYMEX Henry Hub ("HH") swap contracts coupled with basis swap contracts that convert the HH price index point to other price indexes. The asset and liability values attributable to the Company's gas derivatives as of December 31, 2008 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH gas, (iii) averages of forward posted price quotes supplied by independent brokers who are active in buying and selling gas derivatives at the indexes other than HH and (iv)

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the applicable credit-adjusted risk-free rate yield curve. As of December 31, 2007, the fair value of gas derivatives were estimated from quotes provided by the counterparties to these derivative contracts.

The Company corroborated independent broker-supplied forward price quotes by comparing price quote samples to alternate observable market data.

Foreign exchange rate derivatives. As of December 31, 2007, the fair value of foreign exchange rate derivatives were estimated from quotes provided by the counterparties to these derivative contracts.

Notes receivable. The fair value of the notes receivable approximates the carrying value at December 31, 2008 based on the adequacy of collateral security and interest yields. The current portion of the notes receivable, amounting to $6.2 million and $3.6 million as of December 31, 2008 and 2007, respectively, is included in other current assets, net and the noncurrent portions of the notes receivable are included in other assets, net in the accompanying consolidated balance sheets.

Canadian escrow deposit account. The Canadian escrow deposit account was a deposit account denominated in Canadian dollars. The carrying value of this account was measured in U.S. dollars based on the Canadian dollar to U.S. dollar exchange rate of .9984 as of December 31, 2007. Consequently, the carrying value of the account approximated its fair value as of December 31, 2007, and was included in other current assets, net in the accompanying consolidated balance sheet as of December 31, 2007.

Credit Facility. The fair value of the Company's credit facility as of December 31, 2008 is based on (i) contractual interest and fees, (ii) forward active market-quoted LIBOR rate yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's credit facility measurements represent Level 2 inputs in the hierarchy priority.

As of December 31, 2007, the carrying amount of borrowings outstanding under the Company's credit facility approximated fair value because those instruments bore interest at variable market rates. The fair values of each of the senior note issuances were determined based on quoted market prices for each of the issues. See Note F for additional information regarding the Company's long-term debt.

Concentrations of credit risk. As of December 31, 2008, the Company's primary concentrations of credit risks are the risks of collecting accounts receivable – trade and notes receivable and the risk of counterparties' failure to perform under derivative obligations. See Note B for information regarding the Company's accounts receivable – trade and notes receivable, including collateralization of notes receivable.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative assets receivable from the defaulting party. See Note J for additional information regarding the Company's derivative activities.

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NOTE F. Long-term Debt

Long-term debt, including the effects of net deferred fair value hedge losses and issuance discounts and premiums, consisted of the following components at December 31, 2008 and 2007:

	December 31, 2008 (in thousands)	2007
Outstanding debt principal balances:		
Line of credit	$ 913,000	$ 1,113,000
6.50% senior notes due 2008	—	3,777
5.875% senior notes due 2012	6,110	6,110
5.875% senior notes due 2016	455,385	526,875
6.65% senior notes due 2017	485,100	500,000
6.875% senior notes due 2018	449,500	450,000
7.20% senior notes due 2028	250,000	250,000
2.875% convertible senior notes due 2038	480,000	—
	3,039,095	2,849,762
Issuance discounts and premiums, net	(72,540)	(91,111)
Net deferred fair value hedge losses	(2,508)	(3,160)
Total long-term debt	$ 2,964,047	$ 2,755,491

Credit facility. During April 2007, the Company amended its prior credit agreement with an Amended and Restated 5-Year Revolving Credit Agreement (the "Credit Facility") that matures in April 2012 unless extended in accordance with the terms of the Credit Facility. The Credit Facility provides for initial aggregate loan commitments of $1.5 billion, which may be increased to a maximum aggregate amount of $2.0 billion if the lenders increase their loan commitments or if loan commitments of new financial institutions are added. As of December 31, 2008, the Company had $913 million of outstanding borrowings under the Credit Facility and had $46 million of undrawn letters of credit under the Credit Facility, leaving the Company with $541 million of unused borrowing capacity under the Credit Facility.

Borrowings under the Credit Facility may be in the form of revolving loans or swing line loans. Aggregate outstanding swing line loans may not exceed $150 million. Revolving loans bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus .5 percent or (b) a base Eurodollar rate, substantially equal to LIBOR, plus a margin (the "Applicable Margin") (currently .75 percent) that is determined by a reference grid based on the Company's debt rating. Swing line loans bear interest at a rate per annum equal to the "ASK" rate for Federal funds periodically published by the Dow Jones

Market Service plus the Applicable Margin. Letters of credit outstanding under the Credit Facility are subject to a per annum fee, representing the Applicable Margin plus .125 percent. The Company pays commitment fees on the undrawn amounts under the Credit Facility that are determined by reference to a grid based on the Company's debt rating (0.75 percent per annum at December 31, 2008).

The Credit Facility contains certain financial covenants, which include the maintenance of a ratio of total debt to book capitalization less intangible assets, accumulated other comprehensive income and certain noncash asset impairments, not to exceed .60 to 1.0. The covenants also include the maintenance of a ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.75 to 1.0 until the Company achieves an investment grade rating by Moody's Investors Service, Inc. or Standard & Poors Ratings Group, Inc. The variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) are subject to adjustment by the lenders and, therefore, the amount that the Company may borrow under the Credit Facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items. The lenders may declare any outstanding obligations under the Credit Facility immediately due and payable upon the occurrence, and during the continuance of, an event of default, which includes a defined change in control of the Company. As of December 31, 2008, the Company was in compliance with all of its debt covenants.

In May 2008, Pioneer Southwest entered into a $300 million unsecured revolving credit facility with a syndicate of banks, which matures in May 2013 (the “Pioneer Southwest Credit Facility”). The Pioneer Southwest Credit Facility is available for general partnership purposes, including working capital, capital expenditures and distributions. Borrowings under the Pioneer Southwest Credit Facility may be in the form of Eurodollar rate loans, base rate committed loans or swing line loans. Eurodollar rate loans bear interest annually at LIBOR, plus a margin (the “Applicable Rate”) (currently 0.875 percent) that is determined by a reference grid based on Pioneer Southwest’s consolidated leverage ratio. Base rate committed loans bear interest annually at a base rate equal to the higher of (i) the Federal Funds Rate plus 0.5 percent or (ii) the Bank of America prime rate (the “Base Rate”) plus a margin (currently zero percent). Swing line loans bear interest annually at the Base Rate plus the Applicable Rate. As of December 31, 2008, there were no outstanding borrowings under the Pioneer Southwest Credit Facility.

The Pioneer Southwest Credit Facility contains certain financial covenants, including (i) the maintenance of a quarter end maximum leverage ratio of not more than 3.5 to 1.00, (ii) an interest coverage ratio (representing a ratio of earnings before depreciation, depletion and amortization; impairment of long-lived assets; exploration expense; accretion of discount on asset retirement obligations; interest expense; income taxes; gain or loss on the disposition of assets; noncash commodity hedge related activity; and noncash equity-based compensation to interest expense) of not less than 2.5 to 1.0 and (iii) the maintenance of a ratio of the net present value of Pioneer Southwest’s projected future cash flows from its oil and gas assets to total debt of at least 1.75 to 1.0.

Because of the net present value covenant contained in the agreement, borrowings under the Pioneer Southwest Credit Facility are currently limited to approximately $200 million. The variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) are subject to adjustment by the lenders. As a result, further declines in commodity prices could reduce Pioneer Southwest's borrowing capacity under the Pioneer Southwest Credit Facility. In addition, the Pioneer Southwest Credit Facility contains various covenants that limit, among other things, Pioneer Southwest's ability to grant liens, incur additional indebtedness, engage in a merger, enter into transactions with affiliates, pay distributions or repurchase equity and sell its assets. If any default or event of default (as defined in the Pioneer Southwest Credit Facility) were to occur, the Pioneer Southwest Credit Facility would prohibit Pioneer Southwest from making distributions to unitholders. Such events of default include, among others, nonpayment of principal or interest, violations of covenants, bankruptcy and material judgments and liabilities.

Senior notes. During March 2007, the Company issued $500 million of 6.65% senior notes due 2017 (the “6.65% Notes”) and received proceeds, net of issuance discount and underwriting costs, of $494.8 million. The Company used the net proceeds from the issuance of the 6.65% Notes to reduce indebtedness under its credit facility.

On August 15, 2007, $32.1 million of the Company’s 8.25% senior notes matured and were repaid with borrowings under the Company’s credit facility. On January 15, 2008, $3.8 million principal amount of the Company’s 6.50% senior notes (the “6.50% Senior Notes”) matured and were repaid.

Senior convertible notes. During January 2008, the Company issued $500 million principal amount of 2.875% Senior Convertible Notes and received proceeds, net of approximately $11.3 million of underwriter discounts and offering costs, of approximately $488.7 million. The Company used the net proceeds from the offering to reduce outstanding borrowings under its credit facility.

The 2.875% Senior Convertible Notes will be convertible under certain circumstances, using a net share settlement process, into a combination of cash and the Company's common stock pursuant to a formula. The initial base conversion price is approximately $72.60 per share (subject to adjustment in certain circumstances), which is equivalent to an initial base conversion rate of 13.7741 common shares per $1,000 principal amount of convertible notes. In general, upon conversion of a note, the holder of such note will receive cash equal to the principal amount of the note and the Company's common stock for the note's conversion value in excess of such principal amount. If at the time of conversion the applicable price of the Company's common stock exceeds the base conversion price, holders will receive up to an additional 8.9532 shares of the Company's common stock per $1,000 principal amount of notes, as determined pursuant to a specified formula.

The 2.875% Senior Convertible Notes mature on January 15, 2038 (the "Maturity Date"). The Company may redeem the 2.875% Senior Convertible Notes for cash at any time on or after January 15, 2013 at a price equal to 100 percent of the principal amount plus accrued and unpaid interest. Holders of the 2.875% Senior Convertible Notes may require the Company to purchase their 2.875% Senior Convertible Notes for cash at a price equal to 100 percent of the principal amount plus accrued and unpaid interest if certain defined fundamental changes occur, as defined in the agreement, or on January 15, 2013, 2018, 2023, 2028 or 2033. Additionally, holders may convert their notes at their option in the following circumstances:

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- Following defined periods during which the reported sales prices of the Company's common stock exceeds 130 percent of the base conversion price (initially $72.60 per share):
- During five-day periods following defined circumstances when the trading price of the 2.875% Senior Convertible Notes is less than 97 percent of the price of the Company’s common stock times a defined conversion rate;
- Upon notice of redemption by the Company; and
- During the period beginning October 15, 2037, and ending at the close of business on the business day immediately preceding the Maturity Date.

Interest on the principal amount of the 2.875% Senior Convertible Notes is payable semiannually in arrears on January 15 and July 15 of each year, beginning July 15, 2008. Beginning on January 15, 2013, during any six-month period thereafter from January 15 to July 14 and from July 15 to January 14, if the average trading day price of a 2.875% Senior Convertible Note for the five consecutive trading days immediately preceding the first day of the applicable six-month interest period equals or exceeds $1,200, interest on the principal amount of the 2.875% Senior Convertible Notes will be 2.375% solely for the relevant interest period.

The Company’s senior notes and senior convertible notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Company is a holding company that conducts all of its operations through subsidiaries; consequently, the senior notes and senior convertible notes are structurally subordinated to all obligations of its subsidiaries. Interest on the Company’s senior notes and senior convertible notes is payable semiannually.

Early extinguishment of debt. During December 2008, the Company repurchased $20.0 million principal amount of its outstanding $500 million of 2.875% Senior Convertible Notes, $71.5 million principal amount of its outstanding $526.9 million of 5.875% senior notes due July 15, 2016, $14.9 million principal amount of its outstanding $500.0 million of 6.65% senior notes due March 15, 2017 and $500 thousand principal amount of its outstanding $450.0 million of 6.875% senior notes due April 30, 2018. Associated therewith, the Company recognized a gain of $23.2 million, which is included in interest and other income in the accompanying consolidated statement of operations for the year ended December 31, 2008. During 2006, the Company repurchased $346.2 million of its outstanding $350.0 million of 6.50% Senior Notes. The Company recognized a charge of $8.1 million in 2006 associated with the early extinguishment of the 6.50% Senior Notes, which is included in other expense in the accompanying consolidated statement of operations for the year ended December 31, 2006.

Principal maturities. Principal maturities of long-term debt at December 31, 2008, are as follows (in thousands):

2009	$ —
2010	$ —
2011	$ —

2012	$ 919,110
2013	$ 480,000
Thereafter	$ 1,639,985

The principal maturities during 2013 in the preceding table represent the Company's 2.875% Senior Convertible Notes, which are subject to repurchase at the option of the holders in 2013.

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Interest expenses. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Cash payments for interest	$ 156,002	$ 139,624	$ 114,745
Accretion/amortization of discounts or premiums on loans	7,315	6,707	6,096
Accretion of discount on derivative obligations	3,151	7,306	2,529
Accretion of discount on postretirement benefit obligations	631	1,150	1,037
Amortization of net deferred hedge losses (see Note J)	483	434	14
Amortization of capitalized loan fees	3,703	1,452	1,366
Net changes in accruals	1,227	11,149	(6,571)
Interest incurred	172,512	167,822	119,216
Less capitalized interest	(18,935)	(32,552)	(12,166)
Total interest expense	$ 153,577	$ 135,270	$ 107,050

NOTE G. Related Party Transactions

The Company, through a wholly-owned subsidiary, serves as operator of properties in which it and its affiliated partnerships have an interest. Accordingly, the Company receives producing well overhead and other fees related to the operation of the properties. The affiliated partnerships also reimburse the Company for their allocated share of general and administrative charges. Reimbursements of fees are recorded as reductions to general and administrative expenses in the Company's consolidated statements of operations.

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
	$ 2,064	$ 1,835	$ 1,635

Receipt of lease operating and supervision charges in accordance with standard industry operating agreements			
Reimbursement of general and administrative expenses	$ 415	$ 364	$ 348

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NOTE H.   Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors (the "Board") approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first ten percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were $1.6 million, $1.4 million and $1.3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

401(k) plan. The PNR USA 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of PNR USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount up to 80 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by PNR USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's base compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins with the participant's date of hire. During the years ended December 31, 2008, 2007 and 2006, the Company recognized compensation expense of $11.4 million, $10.9 million and $9.3 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In May 2006, the Company's stockholders approved a new Long-Term Incentive Plan, which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units, restricted stock and restricted stock units to directors, officers and employees of the Company. The Long-Term Incentive Plan provides for the issuance of 4.6 million incentive awards.

The following table shows the number of awards available under the Company's Long-Term Incentive Plan at December 31, 2008:

Approved and authorized awards	4,600,000
Awards issued after May 3, 2006	(2,366,414)
Awards available for future grant	2,233,586

For the 2008-2009 director year, the Company’s non-employee directors were offered a choice to receive their annual fee retainers as (i) 100 percent in restricted stock units, (ii) 100 percent in cash or (iii) a combination of 50 percent cash and 50 percent restricted stock units. All non-employee directors also received an annual equity grant of restricted stock units.

Compensation costs. On January 1, 2006, the Company adopted SFAS 123(R) as more fully described in Note B, and eliminated $45.8 million of deferred compensation in stockholders’ equity and reduced a like amount of additional paid-in capital in the consolidated balance sheets. Such amounts will be amortized to compensation expense over the vesting periods of the awards.

Adoption of SFAS 123(R) required the Company to prospectively (i) recognize the value of the unvested stock options, which was approximately $959 thousand and (ii) recognize compensation expense associated with the Company’s ESPP. The Company’s recognition of compensation expense attributable to restricted stock awards did not change upon adoption of SFAS 123(R).

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As of December 31, 2008, there was approximately $48.3 million of unrecognized compensation expense related to unvested share-based compensation plan awards, primarily related to restricted stock and performance unit awards. As of December 31, 2008, unrecognized compensation expense related to unvested share-based compensation plan awards is being recognized on a straight-line basis over the remaining vesting periods of the awards, which is a remaining weighted average period of less than three years.

Restricted stock awards. During 2008, 2007 and 2006, the Company issued 1,170,026, 831,799 and 736,642, respectively, restricted units or shares of the Company's common stock as compensation to directors, officers and employees of the Company.

The following table reflects the outstanding restricted stock awards as of December 31, 2008, 2007 and 2006 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2008		**2007**		**2006**	
	Number Of Shares	**Weighted Average Price**	**Number Of Shares**	**Weighted Average Price**	**Number Of Shares**	**Weighted Average Price**
Restricted stock awards:						
Outstanding at beginning of year	2,158,594	$ 40.90	2,126,547	$ 39.32	1,966,223	$ 36.90
Units or shares granted	1,170,026	$ 45.59	831,799	$ 40.61	736,642	$ 43.44
Units or shares forfeited	(148,404)	$ 43.21	(96,811)	$ 41.12	(190,538)	$ 39.32
Lapse of restrictions	(1,177,949)	$ 40.23	(702,941)	$ 35.74	(385,780)	$ 34.84
Outstanding at end of year	2,002,267	$ 43.87	2,158,594	$ 40.90	2,126,547	$ 39.32

Stock option awards. The Company did not grant any stock options during 2008, 2007 or 2006.

A summary of the Company's stock option plans as of December 31, 2008, 2007 and 2006, and changes during the years then ended, are presented below:

Year Ended December31,					
2008		**2007**		**2006**	
Number	**Weighted Average**	**Number**	**Weighted Average**	**Number**	**Weighted Average**

	Of Shares	Price	Of Shares	Price	Of Shares	Price
Nonstatutory stock options:						
Outstanding at beginning of year	974,745	$ 20.99	1,601,495	$ 20.50	2,685,398	$ 20.32
Options forfeited	(1,825)	$ 20.83	(5,790)	$ 33.54	(267,851)	$ 22.60
Options exercised	(312,401)	$ 20.19	(620,960)	$ 19.62	(816,052)	$ 19.22
Outstanding at end of year	660,519	$ 21.36	974,745	$ 20.99	1,601,495	$ 20.50
Exercisable at end of year	660,519	$ 21.36	974,745	$ 20.99	1,601,495	$ 20.50

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The following table summarizes information about the Company's stock options outstanding and exercisable at December 31, 2008:

	Options Outstanding and Exercisable			
Range of Exercise Price	Number Outstanding at December 31, 2008	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value at December 31, 2008 (in thousands)
$5 - $11	31,415	1.6 years	$ 10.37	$ 183
$12 - $18	261,829	0.7 years	$ 17.87	55
$19 - $26	367,275	1.3 years	$ 24.79	—
	660,519			$ 238

Performance unit awards. During 2008 and 2007, the Company awarded performance units to certain of the Company's officers under the Long-Term Incentive Plan. The following table summarizes the changes in performance unit awards during the years ended December 31, 2008 and 2007:

	Year Ended December 31,	
	2008	2007
Beginning performance unit awards	142,326	—
Awards	162,951	145,820
Lapsed restrictions	—	(817)
Forfeitures	(9,834)	(2,677)
Ending performance unit awards	295,443	142,326

A maximum of 394,460 shares of the Company's common stock may be issued under the 2008 performance unit awards after a 34 month service period ending on December 31, 2010. A maximum of 344,148 shares of the Company's common stock may be issued under the 2007 performance unit awards after a 34 month service period ending on December 31, 2009. The actual shares, if any, to be issued at the end of the service periods will be based on a total share return ("TSR") market objective ranking the Company's TSR against a defined peer group's individual TSRs. The aggregate grant date fair values of the outstanding performance unit awards is $11.7 million, based on a per-unit fair value of $37.01 and $42.36 for the 2008 and 2007 awards, respectively, as of their grant dates, which amounts were determined using the Monte Carlo simulation method and is being recognized as compensation expense ratably over the service period. The Company recognized $5.5 million and $1.8 million, respectively, of compensation expense attributable to the performance unit awards during 2008 and 2007.

Employee Stock Purchase Plan

The Company has an ESPP that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the eight-month offering period (January 1 to August 31). Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower. During the years ended December 31, 2008, 2007 and 2006, the Company recognized compensation expense of $422 thousand, $606 thousand and $669 thousand, respectively, associated with the ESPP.

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Postretirement Benefit Obligations

At December 31, 2008 and 2007, the Company had recorded $9.6 million and $10.5 million, respectively, of unfunded accumulated postretirement benefit obligations, the current and noncurrent portions of which are included in other current liabilities and other liabilities and minority interests, respectively, in the accompanying consolidated balance sheets. These obligations are comprised of five plans of which four relate to predecessor entities that the Company acquired in prior years. These plans had no assets as of December 31, 2008 or 2007. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

At December 31, 2008, the accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $5.7 million of unfunded accumulated postretirement benefit obligations and by the Company for one plan representing $3.9 million of unfunded accumulated postretirement benefit obligations. Interest costs at an annual rate of 6.22 percent of the periodic undiscounted accumulated postretirement benefit obligations were employed in the valuations of the benefit obligations. Certain of the aforementioned plans provide for medical and dental cost subsidies for plan participants. Annual medical cost escalation trends of ten percent were forecasted for 2009, declining to five percent in 2014 and thereafter, and annual dental cost escalation trends of seven percent were forecasted for 2009, declining to five percent in 2012 and thereafter, were employed to estimate the accumulated postretirement benefit obligations associated with the medical and dental cost subsidies, respectively.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands)		
Beginning accumulated post retirement benefit obligations	$ 10,494	$ 19,837	$ 18,576
Net benefit payments	(1,526)	(968)	(1,234)
Service costs	190	1,036	816
Net actuarial losses (gains)	(177)	(10,561)	642
Accretion of interest	631	1,150	1,037
Ending accumulated postretirement benefit obligations	$ 9,612	$ 10,494	$ 19,837

Estimated benefit payments and service/interest costs associated with the plans for the year ending December 31, 2009 are $1.1 million and $885 thousand, respectively.

The Company adopted the provisions of SFAS 158 “Employers Accounting for Defined Benefit Pension and Other Postretirement Plans” (“SFAS 158”), effective December 31, 2006. The Company previously recognized the unfunded status of its defined benefit postretirement plans and currently recognizes periodic changes in its defined benefit postretirement plans as components of service costs in the period of change as allowed by SFAS 158. Consequently, the adoption of SFAS 158 did not have a material impact on the Company’s liquidity, financial position or results of operations.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers, subsidiary company officers and certain key employees. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total $44.1 million.

Indemnifications. The Company has indemnified its directors and certain of its officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

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Legal actions. The Company is party to the legal actions that are described below. 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. The Company will continue to evaluate its litigation on a quarter-by-quarter basis and will establish and adjust any litigation reserves as appropriate to reflect its assessment of the then current status of litigation.

MOSH Holding. On April 11, 2005, the Company and its principal United States subsidiary, Pioneer Natural Resources USA, Inc., were named as defendants in *MOSH Holding, L.P. v Pioneer Natural Resources Company; Pioneer Natural Resources USA, Inc.; Woodside Energy (USA) Inc.; and JPMorgan Chase Bank, N.A.,* ("JP Morgan") as Trustee of the Mesa Offshore Trust (the "Trust"), which is before the Judicial District Court of Harris County, Texas (334th Judicial District). Subsequently, Dagger-Spine Hedgehog Corporation ("Dagger-Spine") and a group of approximately fifty other unitholders ("Unitholder Group") each filed a Petition in Intervention in the lawsuit to assert the same claims against the defendants. The Unitholder Group subsequently voluntarily non-suited leaving only Dagger-Spine and MOSH Holding, L.P. as Plaintiffs/Interveners in this lawsuit (collectively MOSH Holding L.P. and Dagger-Spine are referred to as "Plaintiffs"). Plaintiffs are unit holders in the Trust, which was created in 1982 as a partner in the general partnership that holds an overriding royalty interest in certain oil and gas leases offshore Louisiana and Texas (the "Partnership"). The Company owns the managing general partner interest in the Partnership. Plaintiffs allege that the Company, together with Woodside Energy (USA) Inc. ("Woodside"), concealed the value of the royalty interest and worked to terminate the Mesa Offshore Trust ("MOT") prematurely and to capture for itself and Woodside profits that belong to MOT. Plaintiffs also allege breaches of fiduciary duty, misapplication of trust property, common law fraud, gross negligence, and breach of the conveyance agreement for the overriding royalty interest. Plaintiffs also allege that the Company did not act as a prudent operator regarding certain activities undertaken with respect to a producing well and that the Company should have undertaken to drill additional wells for the benefit of the Partnership. The relief sought by the Plaintiffs includes monetary and punitive damages and certain equitable relief, including an accounting of expenses, a setting aside of the farmout between the Company and Woodside, and a temporary and permanent injunction.

In July 2007, the Company filed a motion for summary judgment challenging Plaintiffs' standing to prosecute the case and seeking dismissal. The Company also filed a motion for summary judgment challenging the substantive merits of Plaintiffs' claims and seeking dismissal.

In July 2008, the trial court denied the Company's two summary judgment motions. The Company subsequently filed an application for a writ of mandamus as well as request for a stay of the trial proceedings with the court of appeals seeking a reversal of the trial court's refusal to dismiss the lawsuit based upon Plaintiffs' lack of standing. That application and stay motion were denied by the court of appeals and subsequently by the Texas Supreme Court. Trial on the merits of the lawsuit is scheduled for April 13, 2009.

On October 10, 2008, the Company unconditionally offered without compensation its complete interest, including its working interest, in the Brazos Block A-39 tract to Plaintiffs and to the Trustee (on behalf of all the unit holders). Plaintiffs rejected the Company's tender, while the Trustee, by letter dated January 13, 2009, has instructed the Company to sell by public auction the Company's complete interest in the Brazos Block A-39 tract together with the all of the Partnership's interests in the Brazos Block A-39 and the other active Trust property, West Delta Block 61. The Company has engaged The Oil and Gas Clearinghouse to carry out the sale via a public auction that is scheduled to take place on

March 18, 2009.

The Company believes the claims made by the Plaintiffs in the MOSH Holding lawsuit are without merit and intends to defend the lawsuit vigorously. The Company cannot predict whether the outcome of this proceeding will be adverse to the Company and if so, whether such an outcome will materially impact the Company's liquidity, financial position or future results of operations.

Colorado Notice of Violation. On May 13, 2008, the Company was served with a Notice of Violation/Cease and Desist Order by the State of Colorado Department of Public Health and Environmental Water Quality Control Division. The Notice alleges violations of stormwater discharge permits in the Company's Raton Basin and Lay Creek operations, specifically deficiencies in the Company's stormwater management plans, failure to implement and maintain best management practices to protect stormwater runoff and failure to conduct inspections of the stormwater management system. The Company has filed an answer to the Notice asserting

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defenses to the allegations. The Company does not believe that the outcome of this proceeding will materially impact the Company's liquidity, financial position or future results of operations.

SemGroup accounts receivable. The Company is a creditor in the bankruptcy of SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), which filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code on July 22, 2008 in the U.S. Bankruptcy Court for the District of Delaware. SemGroup purchased condensate from the Company and, at the time of the bankruptcy filings, was indebted to the Company for approximately $29.6 million. Subsequent to the bankruptcy filings, SemGroup, by contractual right, continued to purchase condensate from the Company until the end of July 2008, at which time the Company suspended condensate sales to SemGroup. During August 2008, SemGroup paid the Company approximately $5.3 million, representing amounts due for post-petition purchases. As of December 31, 2008, the Company had approximately $29.6 million of delinquent receivables from SemGroup, representing pre-petition claims.

The Company believes that it is probable that the collection of the pre-petition claims will not occur for a protracted period of time and that some of its claims may be uncollectible. Consequently, the Company recorded a bad debt expense of approximately $19.6 million during the third quarter 2008, which reduced the carrying value of the claims to approximately $10.0 million.

SemGroup's reorganization effort is still in its early stages and determination of the exact amount of uncollectible claims is not presently determinable. It is reasonably possible that the Company will not collect the claims or that collected amounts will be less than $10.0 million. If those circumstances occur, the Company would recognize additional bad debt expense to further reduce the carrying value of its claims. The Company believes that any losses relating to its failure to collect its SemGroup claims would not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations.

The condensate supplied to SemGroup was produced from Pioneer's West Panhandle gas field and processed at Pioneer's Fain plant in the Texas Panhandle. During August 2008, the Company began selling its condensate to alternate purchasers. The Company has not experienced any disruption in its West Panhandle operations and sales as a result of these actions.

Obligations following divestitures. In April 2006, the Company provided the purchaser of its Argentine assets certain indemnifications. The Company remains responsible for certain contingent liabilities related to such indemnifications, subject to defined limitations. The Company does not believe that these obligations, which primarily pertain to matters of litigation, environmental contingencies, royalty obligations and income taxes, are probable of having a material impact on its liquidity, financial position or future results of operations.

The Company has also retained certain liabilities and indemnified buyers for certain matters in connection with other divestitures, including the sale in 2007 of its Canadian assets.

Drilling commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future. The Company also enters into agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is expended or rig services are provided.

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Lease agreements. The Company leases offshore production facilities, drilling rigs, equipment and office facilities under noncancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2008, 2007 and 2006 were approximately \$49.6 million, \$47.0 million and \$46.8 million, respectively, which includes \$1.7 million and \$9.8 million, respectively, associated with discontinued operations in 2007 and 2006. Future minimum lease commitments under noncancellable operating leases at December 31, 2008 are as follows (in thousands):

2009	\$ 20,072
2010	\$ 15,321
2011	\$ 13,989
2012	\$ 13,442
2013	\$ 11,761
Thereafter	\$ 70,803

Transportation agreements. The Company is party to contractual commitments with pipeline carriers for the future transportation of gas production from certain of the Company's properties located in the Raton and Uinta Basins. The Raton Basin transportation commitments averaged approximately 226 million cubic feet ("MMcf") of gross gas volumes per day during 2008, including fuel commitments, and will average approximately 219 MMcf per day of gross gas volume during 2009, decreasing to approximately 204 MMcf per day per day during 2010, 182 MMcf per day during 2011, 122 MMcf per day during 2012, 102 MMcf per day during 2013 and 35 MMcf per day during 2014, the year of termination. Certain of these commitments were extended during the first quarter 2009.

The Uinta Basin transportation commitments commenced during June 2007 and averaged approximately 8 MMcf of gross gas volumes per day during 2008, including fuel commitments, and will average approximately 13 MMcf per day during 2009, and 15 MMcf per day thereafter. The Uinta Basin transportation commitments terminate during 2012, but may be extended for a period of up to three years at the option of the Company.

Future minimum transportation fees under the Company's gas transportation commitments at December 31, 2008 are as follows (in thousands):

2009	\$ 25,972
2010	\$ 24,635
2011	\$ 21,567
2012	\$ 14,536
2013	\$ 10,849
Thereafter	\$ 21,117

NOTE J. Derivative Financial Instruments

The Company uses financial derivative contracts to manage exposures to commodity price, interest rate and foreign currency fluctuations. The Company generally does not enter into derivative financial instruments for speculative or trading purposes. The Company also may enter physical delivery contracts to effectively provide commodity price protection. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, physical delivery contracts are not accounted for as derivative financial instruments in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is determined in accordance with SFAS 157 and is generally determined based on the credit-adjusted present value difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of effective cash flow hedges are recorded as a component of AOCI - Hedging, which is later transferred to earnings when the hedged transaction is recognized in earnings. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of changes in the fair value of hedge derivatives, are recorded in the earnings of the period of change. The ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged.

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Effective January 31, 2009, the Company discontinued hedge accounting on all existing hedge contracts. Net gains and losses deferred in AOCI – Hedging associated with these contracts as of January 31, 2009 will be reclassified to earnings over the periods the original contracts impact earnings.

Fair value hedges. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate derivative contracts, with the objective of reducing the Company's costs of capital. As of December 31, 2008 and December 31, 2007, the Company was not a party to any fair value hedges.

Cash flow hedges. The Company utilizes commodity swap and collar contracts 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 December 31, 2008, all of the Company's open commodity hedges were designated as hedges of United States forecasted sales. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness and forward currency exchange agreements to reduce the effect of exchange rate volatility.

Non-hedge commodity derivatives. The Company utilizes non-hedge derivative contracts to mitigate price risk associated with certain of its production.

Oil prices. All material physical sales contracts governing the Company's oil production have been tied directly or indirectly to the New York Mercantile Exchange ("NYMEX") prices. The following table sets forth the volumes in barrels ("Bbl") underlying the Company's outstanding oil hedge and non-hedge contracts and the weighted average NYMEX prices per Bbl for those contracts as of December 31, 2008:

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Outstanding Average**
Average daily oil production hedged:					
2009 – Swap Contracts					
Volume (Bbl)	2,500	2,500	2,500	2,500	2,500
Price per Bbl	$ 99.26	$ 99.26	$ 99.26	$ 99.26	$ 99.26

2010 – Swap Contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl	$ 98.32	$ 98.32	$ 98.32	$ 98.32	$ 98.32
2011 – Collar Contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl	$ 115.00-170.00	$ 115.00-170.00	$ 115.00-170.00	$ 115.00-170.00	$ 115.00-170.00
Average daily oil production non-hedge derivatives (a):					
2009 – Swap Contracts					
Volume (Bbl)	9,689	12,000	12,000	12,000	11,430
Price per Bbl	$ 50.34	$ 50.30	$ 50.30	$ 50.30	$ 50.31

(a) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into additional non-hedge (i) swap contracts for approximately 10,236 Bbls per day of the Company’s 2009 production at an average price of $54.91 per Bbl and (ii) collar contracts for approximately 1,830 Bbls per day of the Company’s 2009 production with a floor price of $52.00 per Bbl and a ceiling price of $70.38 per Bbl.

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The Company reports average oil prices per Bbl including the effects of oil quality adjustments, amortization of deferred volumetric production payment (“VPP”) revenue and the net effect of oil hedges. The following table sets forth (i) the Company’s oil prices from continuing operations, both reported (including hedge results and amortization of deferred VPP revenue) and realized (excluding hedge results and amortization of deferred VPP revenue), (ii) amortization of deferred VPP revenue to oil revenue from continuing operations and (iii) the net effect of settlements of oil price hedges on oil revenue from continuing operations for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Average price reported per Bbl	$ 75.47	$ 66.08	$ 65.51
Average price realized per Bbl	$ 96.19	$ 70.91	$ 63.42
VPP increase to oil revenue (in millions)	$ 104.1	$ 109.7	$ 116.1
Decrease to oil revenue from hedging activity (in millions) (a)	$ 336.2	$ 154.1	$ 97.6

(a) Excludes hedge losses of $12.3 million attributable to discontinued operations for the year ended December 31, 2006.

NGL prices. All material physical sales contracts governing the Company’s NGL production have been tied directly or indirectly to Mont Belvieu prices. The following table sets forth the volumes in Bbls under outstanding NGL hedge contracts and the weighted average Mont Belvieu prices per Bbl for those contracts at December 31, 2008:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily NGL production hedged (a):					
2009 – Swap Contracts					
Volume (Bbl)	1,250	1,250	1,250	1,250	1,250
Price per Bbl	$ 48.97	$ 48.99	$ 49.00	$ 49.00	$ 48.99
2010 – Swap Contracts					
Volume (Bbl)	1,250	1,250	1,250	1,250	1,250
Price per Bbl	$ 47.36	$ 47.37	$ 47.38	$ 47.38	$ 47.38

(a) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into non-hedge swap contracts for approximately 1,767 Bbls per day of the Company’s 2009 production at an average price of $27.12 per Bbl.

The Company reports average NGL prices per Bbl including the effects of NGL quality adjustments and the net effect of NGL hedges. The following table sets forth (i) the Company’s NGL prices from continuing operations, both reported (including hedge results) and realized (excluding hedge results) and (iii) the net effect of NGL price hedges on NGL revenue from continuing operations for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Average price reported per Bbl	$ 51.34	$ 41.60	$ 35.24
Average price realized per Bbl	$ 51.59	$ 41.60	$ 35.24
Decrease to NGL revenue from hedging activity (in millions)	$ 1.8	$ —	$ —

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Gas prices. The Company employs a policy of using derivatives associated with a portion of its gas production based on the index price upon which the gas is actually sold in order to mitigate the basis risk between NYMEX prices and actual index prices, or based on NYMEX prices, if NYMEX prices are highly correlated with the index price. The following table sets forth the volumes in million British thermal units ("MMBtu") under outstanding gas hedge and non-hedge contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2008:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily gas production hedged:					
2009 – Swap Contracts					
Volume (MMbtu)	5,000	5,000	5,000	5,000	5,000
Price per MMBtu	$ 8.04	$ 8.04	$ 8.04	$ 8.04	$ 8.04
2010 – Swap Contracts					
Volume (MMbtu)	5,000	5,000	5,000	5,000	5,000
Price per MMBtu	$ 7.73	$ 7.73	$ 7.73	$ 7.73	$ 7.73
Average daily gas production non-hedge derivatives (a):					
2009 – Swap Contracts					
Volume (MMbtu)	—	90,000	90,000	30,326	52,767
Price per MMBtu	$ —	$ 6.12	$ 6.12	$ 6.12	$ 6.12
2009 – Basis Swap Contracts					
Volume (MMbtu)	150,000	120,000	120,000	120,000	127,397
Price per MMBtu	$ (1.19)	$ (1.18)	$ (1.18)	$ (1.18)	$ (1.18)
2010 – Basis Swap Contracts					
Volume (MMbtu)	80,000	80,000	80,000	80,000	80,000
Price per MMBtu	$ (0.90)	$ (0.90)	$ (0.90)	$ (0.90)	$ (0.90)
2011 – Basis Swap Contracts					
Volume (MMbtu)	50,000	50,000	50,000	50,000	50,000
Price per MMBtu	$ (0.83)	$ (0.83)	$ (0.83)	$ (0.83)	$ (0.83)
2012 – Basis Swap Contracts					
Volume (MMbtu)	10,000	10,000	10,000	10,000	10,000

Price per MMBtu	$ (0.79)	$ (0.79)	$ (0.79)	$ (0.79)	$ (0.79)
2013 – Basis Swap Contracts					
Volume (MMbtu)	10,000	10,000	10,000	10,000	10,000
Price per MMBtu	$ (0.71)	$ (0.71)	$ (0.71)	$ (0.71)	$ (0.71)

———

(a) Subsequent to December 31, 2008 and as of February 11, 2009, the Company entered into additional non-hedge (i) swap contracts for approximately 43,452 MMBtu and 80,000 MMBtu, respectively, of the Company's 2009 and 2010 production at an average price of $6.12 per MMBtu and $6.53 per MMBtu, respectively, (ii) basis swap contracts for approximately 48,438 MMBtu, 40,000 MMBtu 10,000 MMBtu and 10,000 MMBtu, respectively, of the Company's 2009-2012 production at an average price differential of $1.12 per MMBtu, $.89 per MMBtu, $.75 per MMBtu and $.76 per MMBtu, respectively.

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The Company reports average gas prices per Mcf including the effects of Btu content, gas processing, shrinkage adjustments, amortization of deferred VPP revenue and the net effect of gas hedges. The following table sets forth (i) the Company's gas prices from continuing operations, both reported (including hedge results and amortization of deferred VPP revenue) and realized (excluding hedge results and amortization of deferred VPP revenue), (ii) amortization of deferred VPP revenue to gas revenue from continuing operations and (iii) the net effect of settlements of gas price hedges on gas revenue from continuing operations for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Average price reported per Mcf	$ 7.66	$ 7.26	$ 6.15
Average price realized per Mcf	$ 7.40	$ 6.04	$ 5.96
VPP increase to gas revenue (in millions)	$ 54.1	$ 71.6	$ 74.2
Increase (decrease) to gas revenue from hedging activity (in millions) (a)	$ (17.5)	$ 70.6	$ (53.6)

(a) Excludes hedge gains (losses) of $28.1 million and $(1.2) million attributable to discontinued operations for the year ended December 31, 2007 and 2006, respectively.

Interest rate. During January 2008, the Company entered into interest rate swap contracts and designated the contracts as cash flow hedges of the forecasted interest rate risk associated with a portion of the Company's Credit Facility indebtedness. The interest rate swap contracts are variable-for-fixed-rate swaps on $400 million notional amount of debt at a weighted average fixed annual rate of 2.87 percent, excluding any applicable margins. The interest rate swaps had an effective start date of February 2008, with $200 million terminating during February 2010 and $200 million during February 2011. The Company did not record any ineffectiveness in connection with the interest rate swap contracts.

Hedge ineffectiveness. The Company recognized ineffectiveness amounts related to (i) hedged volumes that exceeded revised forecasts of production volumes due to delays in the start up of production in certain fields and (ii) reduced correlations between the indexes of the financial hedge derivatives and the indexes of the hedged forecasted production for certain fields. Ineffectiveness can be associated with closed contracts (i.e. realized) or can be associated with open positions (i.e. unrealized). During the years ended December 31, 2008, 2007 and 2006, the Company recognized net hedge ineffectiveness income (loss) from continuing operations of $(500) thousand, $(2.1) million and $18 million, respectively.

AOCI - Hedging. As of December 31, 2008 and 2007, AOCI - Hedging represented net deferred gains (losses) of $133.5 and $(228.3) million, respectively. The AOCI - Hedging balance as of December 31, 2008 was comprised of $113.5 million of net deferred hedge gains on the effective portions of open cash flow hedges, $100.4 million of net deferred gains on terminated cash flow hedges (including $2.5 million of net deferred losses on terminated cash flow interest rate hedges) and $80.4 million of associated net deferred tax provisions. The AOCI - Hedging balance as of December 31, 2007 was comprised of $246.4 million of net deferred losses on the effective portions of open cash flow hedges,

$114.7 million of net deferred losses on terminated cash flow hedges (including $3.1 million of net deferred losses on terminated cash flow interest rate hedges) and $132.8 million of associated net deferred tax benefits. The increase in AOCI – Hedging gains during the year ended December 31, 2008 was primarily attributable to the decrease in future commodity prices relative to the commodity prices stipulated in the hedge contracts and the reclassification of net deferred hedge losses to net income as derivatives matured by their terms. The increase in AOCI - Hedging losses during the year ended December 31, 2007 was primarily attributable to increases in future commodity prices relative to the commodity prices stipulated in the hedge contracts, partially offset by the reclassification of net deferred hedge losses to net income as derivatives matured by their terms. The net deferred gains associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The net deferred gains on terminated cash flow hedges are fixed.

During the year ending December 31, 2009, based on current estimates of future commodity prices, the Company expects to reclassify approximately $65.6 million of net deferred gains associated with open commodity hedges and $59.9 million of net deferred gains on terminated commodity hedges from AOCI - Hedging to oil and

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gas revenues. The Company also expects to reclassify approximately $22.3 million of net deferred income tax provisions associated with commodity hedges during the year ending December 31, 2009 from AOCI - Hedging to income tax expense.

Terminated commodity hedges. At times, the Company terminates open commodity hedge positions when the underlying commodity prices reach a point that the Company believes will be the high or low price of the commodity prior to the scheduled settlement of the open commodity position. This allows the Company to maximize gains or minimize losses associated with the open hedge positions. At the time of termination of the hedges, the amounts recorded in AOCI - Hedging are maintained and amortized to earnings over the periods the production was scheduled to occur.

The following table sets forth, as of December 31, 2008, the scheduled amortization of net deferred (gains) and losses on terminated commodity hedges that will be recognized as (increases) and decreases to the Company's future oil and gas revenues:

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
	(in thousands)				
2009 net deferred hedge gains	$ (25,872)	$ (11,449)	$ (11,642)	$ (11,111)	$ (60,074)
2010 net deferred hedge gains	$ (12,081)	$ (12,301)	$ (12,517)	$ (12,581)	$ (49,480)
2011 net deferred hedge losses	$ 873	$ 889	$ 903	$ 906	$ 3,571
2012 net deferred hedge losses	$ 810	$ 791	$ 784	$ 772	$ 3,157

Non-hedge derivatives. During December 2008, the Company entered into commodity derivative contracts that were not designated as hedges under SFAS 133. The Company recognized a loss of $10.6 million associated with the change in value of these non-hedge derivative instruments, which amount is included in other expense in the accompanying consolidated statement of operations for 2008.

During December 2007, the Company entered into foreign exchange rate swaps of Canadian dollars ("CND") for U.S. dollars ("USD"). The foreign exchange rate swaps were economic hedges of a CND-denominated escrow account balance that was funded during November 2007 associated with the sale of Canadian assets (see Note V for additional information regarding the sale of the Company's Canadian assets); however, uncertainty regarding the matching of cash flow timing between the foreign exchange rate swaps and the liquidation of the CND-denominated escrow account caused the Company not to designate the foreign exchange rate swaps as hedges. The foreign exchange rate swaps matured during May 2008 and were for a notional amount of approximately $131.0 million USD. The Company recognized a mark-to-market loss of $1.5 million associated with these derivatives during 2007 and realized a 2008 cash gain of $1.8 million during 2008, which amounts are included in discontinued operations in the accompanying consolidated statement of operations.

NOTE K. Major Customers and Derivative Counterparties

Sales to major customers. The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company records allowances for doubtful accounts based on the agings of accounts receivables and the financial condition of its purchasers and, depending on facts and circumstances, may require purchasers to provide collateral or otherwise secure their accounts. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on the ability of the Company to sell its oil and gas production.

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The following United States purchasers individually accounted for ten percent or more of the consolidated oil, NGL and gas revenues, including the revenues from discontinued operations and the results of commodity hedges, in at least one of the years, during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Plains Marketing LP	13 %	14 %	12 %
Oneok Resources	6 %	11 %	12 %
Occidental Energy Marketing, Inc.	9 %	11 %	11 %
Enterprise Products Partners L.P.	10 %	7 %	8 %

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. As of December 31, 2008, the Company had no derivative counterparties with significant credit risks.

NOTE L. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes the Company's asset retirement obligation transactions during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Beginning asset retirement obligations	$ 208,184	$ 225,913	$ 157,035
Liabilities assumed in acquisitions	2,237	4,751	981
New wells placed on production and changes in estimates (a)	23,637	91,067	122,685
Disposition of wells	—	(30,599)	(44,042)
Liabilities settled	(70,324)	(95,980)	(16,219)

Accretion of discount on continuing operations	8,699	7,028	3,726
Accretion of discount on discontinued operations	—	1,767	1,904
Currency translation	—	4,237	(157)
Ending asset retirement obligation	$ 172,433	$ 208,184	$ 225,913

(a) The change in the 2008 estimate is primarily due to lower year-end prices for oil, NGL and gas being used to calculate proved reserves at December 31, 2008, which had the effect of shortening the economic life of many wells; thus increasing the present value of future retirement obligations. For the years ended December 31, 2007 and 2006, the increases include $66.0 million and $75.0 million, respectively, in reclamation and abandonment estimate revisions for the East Cameron facilities that were destroyed by Hurricane Rita and is reflected in hurricane activity, net in the consolidated statements of operations.

The Company records the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities and minority interests, respectively, in the accompanying consolidated balance sheets. The current portion of the Company's asset retirement obligations totaled $29.9 million and $86.9 million as of December 31, 2008 and 2007, respectively.

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NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Gain on early extinguishment of debt (see Note F)	$ 23,248	$ —	$ —
Alaskan Petroleum Production Tax credits	18,636	74,861	—
Foreign currency remeasurement and exchange gains (a)	8,058	6	361
Interest income	3,312	3,038	14,369
Legal settlements	2,495	—	—
Deferred compensation plan income	2,007	1,247	879
Other income	1,440	3,210	3,689
Credit card rebate	1,178	975	837
Non-hedge derivative settlements (see Note J)	944	—	7,371
Alaskan Exploration Incentive Tax credits	—	—	5,570
Royalty obligation accrual adjustment	—	4,816	—
Sales and other tax refunds	—	3,730	645
Business interruption insurance claim (see Note U)	—	—	7,647
Bad debt recoveries	—	—	2,130
Total interest and other income	$ 61,318	$ 91,883	$ 43,498

(a) The Company's current operations in Africa give rise to, and past operations in Argentina and Canada resulted in, periodic recognition of monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE N. Asset Divestitures

During the years ended December 31, 2008, 2007 and 2006, the Company completed asset divestitures for net proceeds of $292.9 million, $553.7 million and $1.6 billion, respectively. Associated therewith, the Company recorded losses on disposition of assets in continuing operations of $381 thousand, $2.2 million and $6.5 million during the years ended December 31, 2008, 2007 and 2006, respectively, and gains (losses) of $(392) thousand, $100.2 million and $731.8 million in discontinued operations in 2008, 2007 and 2006, respectively. The following describes the significant divestitures:

Canadian divestiture. In November 2007, the Company completed the sale of its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. The net proceeds from the sale of the Canadian subsidiaries includes $132.8 million of proceeds that were deposited by the purchaser into the Company's Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications, which were received in January 2008. Accordingly, the accompanying consolidated statements of cash flows for the years ended December 31, 2008 and 2007, include approximately $132.0 million and $392.9 million of proceeds from disposition of assets, net of cash sold, respectively, pertaining to the sale of the Canadian subsidiaries. As a result of this divestiture, the Company has reclassified the historic results of operations, comprehensive income and cash flows of its Canadian assets to discontinued operations in accordance with SFAS 144.

Deepwater Gulf of Mexico and Argentine divestitures. During 2006, the Company sold its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $725.3 million and its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. Pursuant to SFAS 144, the gain and the results of operations from these assets have been reclassified to discontinued operations. See Note V for additional information.

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Derivative asset divestitures. During 2008, the Company terminated derivative assets prior to their contractual maturity dates. The accompanying consolidated statement of cash flows for the year ended December 31, 2008 includes approximately $155.0 million of proceeds from disposition of assets attributable to these derivative terminations. Net gains attributable to these derivatives are included in AOCI – Hedging as of December 31, 2008. See Note J for additional information regarding the Company's derivative activities.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Bad debt expense (a)	$ 30,119	$ 5,119	$ 4,733
Idle drilling equipment costs (b)	29,761	8,682	275
Rig contract terminations (c)	24,778	—	—
Contingency and environmental accrual adjustments	12,449	14,750	10,119
Non-hedge derivative losses	10,593	—	6,517
Other charges	6,353	1,125	4,957
Colorado severance tax audit adjustment	5,730	—	—
Rig impairment	3,382	—	—
Well servicing operations	3,289	3,245	1,722
Derivative ineffectiveness (See Note J)	499	2,135	(10,595)
Foreign currency remeasurement and exchange losses (d)	112	184	580
Loss on early extinguishment of debt (See Note F)	—	—	8,076
Insurance charges	—	—	4,000
Contingency settlements and costs	—	1,363	1,489
Postretirement benefit obligation revaluation	—	(10,562)	642
Abandoned acquisitions and divestitures	—	3,385	1,775
Total other expense	$ 127,065	$ 29,426	$ 34,290

(a) Includes a $19.6 million SemGroup bad debt allowance in 2008. See Note I for more information.
(b) Represents stacked drilling rig costs under contractual drilling rig commitments.

(c) Represents costs incurred to terminate contractual drilling rig commitments prior to their contractual maturities.

(d) The Company’s current operations in Africa give rise to, and past operations in Argentina and Canada resulted in, periodic recognition of monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE P. Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, “Accounting for Income Taxes” (“SFAS 109”). The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state, local and foreign taxing authorities. Current and estimated tax payments (net of refunds) of $70.3 million, $29.5 million and $153.1 million were made during the years ended December 31, 2008, 2007 and 2006, respectively.

SFAS 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company’s net operating loss carryforwards (“NOLs”) and other deferred tax attributes in the United States, state,

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local and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2008 and 2007, the Company's valuation allowances (relating primarily to foreign tax jurisdictions) were $37.5 million and $24.8 million, respectively.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48") on January 1, 2007. In conjunction with the implementation of FIN 48, the Company analyzed its filing positions for open tax years in all of the United States federal, state and foreign jurisdictions where it has material tax attributes and is required to file income tax returns. Upon adoption, the Company believed that its income tax filing positions and deductions would be substantially sustained on audit and did not anticipate any significant adjustments. Consequently, the Company's adoption of FIN 48 did not have a material impact on the Company. As of December 31, 2008, the Company did not have a liability for unrecognized tax benefits that, if recognized, would affect the Company's effective tax rate and no significant unrecognized tax benefits are anticipated in 2009.

In connection with the adoption of FIN 48, the Company established a policy to account for interest charges with respect to income taxes as interest expense and any penalties, with respect to income taxes, as other expense in the consolidated statement of operations.

The Company files income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. With few exceptions, the Company believes that it is no longer subject to examinations by tax authorities for years before 2003. In January 2009, the Internal Revenue Service ("IRS") began a limited examination of the Company's 2006 U.S. federal income tax return. In addition, the Company's 2004 and 2005 state income tax returns in Colorado are currently under audit. As of December 31, 2008, there are no proposed adjustments or uncertain positions in any jurisdiction that would have a significant affect on the Company's future results of operations or financial position. The Company's earliest open years in its key jurisdictions are as follows:

United States	2005
Various U.S. states	2004
Tunisia	2003
South Africa	2003

Pursuant to Accounting Principles Board ("APB") Opinion No. 23 "Accounting for Income Taxes – Special Areas," the Company historically treated the undistributed earnings in South Africa as permanently reinvested and did not provide for a U.S. tax on such earnings. During the second quarter of 2007, the Company made the determination that it no longer had identifiable plans to reinvest these earnings in South Africa and accordingly began recording deferred tax expense. For the years ended December 31, 2008 and 2007, the Company recorded $15.8 million and $18.9 million, respectively, of U.S. income taxes for the results of operations of its South African subsidiaries.

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The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Income from continuing operations	$ 205,639	$ 112,645	$ 141,021
Income from discontinued operations	(839)	(17,972)	295,501
Changes in goodwill - tax benefits related to stock-based compensation	(307)	961	(1,742)
Changes in stockholders' equity:			
Net deferred hedge gains (losses)	213,151	(28,304)	193,719
Tax benefits related to stock-based compensation	(367)	(3,908)	(4,247)
Translation adjustment	(3,815)	644	8,421
	$ 413,462	$ 64,066	$ 632,673

The Company's income tax provision (benefit) attributable to income from continuing operations consisted of the following for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Current:			
U.S. federal	$ (19,954)	$ (60,320)	$ (54,004)
U.S. state and local	665	331	(52)
Foreign	67,980	48,815	33,316
	48,691	(11,174)	(20,740)
Deferred:			
U.S. federal	123,457	132,246	126,215
U.S. state and local	423	6,576	18,438
Foreign	33,068	(15,003)	17,108
	156,948	123,819	161,761
	$ 205,639	$ 112,645	$ 141,021

Income from continuing operations before income taxes consists of the following for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(in thousands)		
U.S. federal	$ 243,542	$ 309,262	$ 235,049
Foreign	182,911	45,362	56,189
	$ 426,453	$ 354,624	$ 291,238

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Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income from continuing operations are as follows for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
State income taxes (net of federal benefit)	0.3	2.2	1.7
U.S. valuation allowance changes	0.1	0.1	0.3
Foreign valuation allowances	3.2	6.9	8.8
Rate differential on foreign operations	6.1	4.8	4.7
West Africa exit (U.S. federal benefit)	—	(15.4)	—
South Africa expenditures uplift - 50% of development capital expenditures	(0.1)	(4.4)	—
South Africa earnings (U.S. federal income taxes)	3.7	5.3	—
Other	(0.1)	(2.7)	(2.1)
Consolidated effective tax rate	48.2	31.8	48.4

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows as of December 31, 2008 and 2007:

	December 31,	
	2008	2007
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 230,483	$ 103,918
Alternative minimum tax credit carryforwards	21,714	41,668
Net deferred hedge losses	—	132,763
Asset retirement obligations	56,225	71,396
Other	55,436	47,457
Total deferred tax assets	363,858	397,202
Valuation allowances	(37,456)	(24,838)
Net deferred tax assets	326,402	372,364
Deferred tax liabilities:		
	1,545,903	1,317,571

Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes		
South Africa earnings (U.S. federal income taxes)	34,686	18,934
State taxes and other	137,213	147,200
Net deferred hedge gains	79,066	—
Total deferred tax liabilities	1,796,868	1,483,705
Net deferred tax liability	$ (1,470,466)	$ (1,111,341)

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At December 31, 2008, the Company had NOLs in the United States, South Africa and Tunisia for income tax purposes as set forth below, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, the Company has alternative minimum tax NOLs ("AMT NOLs") in the United States which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

Expiration Date	U.S. NOL (in thousands)	AMT NOL	South Africa NOL	Tunisia NOL
2009	$ 29,999	$ 32,003	$ —	$ —
2010	49,858	47,854	—	—
2020	5,588	5,055	—	—
2021	53	—	—	—
2028	440,503	270,787	—	—
Indefinite	—	—	74,000	63,068
	$ 526,001	$ 355,699	$ 74,000	$ 63,068

The Company believes that $41.5 million of the U.S. NOLs and $40.9 million of AMT NOLs are subject to Section 382 of the Internal Revenue Code and will become available to offset future regular or alternative minimum taxable income over the next two years. Pursuant to the provisions of SFAS 123(R), the Company's $230.5 million deferred tax asset related to regular NOL carryforwards at December 31, 2008 is net of $6.6 million of unrealized excess tax benefits from stock based compensation.

The Company's income tax provision (benefit) attributable to income from discontinued operations consisted of the following for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31, 2008 (in thousands)	2007	2006
Current:			
U.S. federal	$ —	$ —	$ 145,623
U.S. state and local	—	—	1,421
Foreign	300	4,915	4,633
	300	4,915	151,677
Deferred:			

U.S. federal	(1,139)	(21,612)	144,387
U.S. state and local	—	—	6,449
Foreign	—	(1,275)	(7,012)
	(1,139)	(22,887)	143,824
	$ (839)	$ (17,972)	$ 295,501

NOTE Q. Income Per Share From Continuing Operations

Basic income per share from continuing operations is computed by dividing income from continuing operations by the weighted average number of common shares outstanding for the period. The computation of diluted income per share from continuing operations reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income from continuing operations were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company.

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The following table is a reconciliation of the basic income from continuing operations to diluted income from continuing operations for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Basic income from continuing operations	$ 220,814	$ 241,979	$ 150,217
Interest expense on convertible notes, net of tax	—	—	1,903
Diluted income from continuing operations	$ 220,814	$ 241,979	$ 152,120

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Weighted average common shares outstanding (a):			
Basic	117,462	120,158	124,359
Dilutive common stock options (b)	247	433	747
Restricted stock awards	698	1,045	989
Contingently issuable - performance shares (c)	90	23	—
Convertible notes dilution (d)	148	—	1,513
Diluted	118,645	121,659	127,608

(a) In 2007, the Board authorized share repurchases of up to $750 million of the Company's common stock. Through December 31, 2008, the Company had repurchased $378.0 million of common stock under this 2007 authorized program.

(b) Common stock options to purchase 91,819 shares of common stock were outstanding but not included in the computation of diluted income per share from continuing operations for 2008 because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computation.

(c) During the years ended December 31, 2008 and 2007, the Company awarded 162,951 and 145,820 of performance unit awards, respectively. Associated therewith, awards for 295,443 and 142,326 performance units remained outstanding (net of forfeitures and lapses) as of December 31, 2008 and 2007, respectively.

(d)

During 2006, holders of the $100 million of 4 3/4% Senior Convertible Notes exercised their conversion rights. During 2008, the Company issued $500 million of 2.875% Senior Convertible Notes and repurchased $20.0 million principal amount during the fourth quarter of 2008. See Note F for information regarding the conversion rights of the note holders.

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NOTE R. Geographic Operating Segment Information

The Company has operations in only one industry segment, that being the oil and gas exploration and production industry; however, the Company is organizationally structured along geographic operating segments or regions. The Company has reportable continuing operations in the United States, South Africa, Tunisia and Other. Other is primarily comprised of operations in Equatorial Guinea and Nigeria.

During 2007, the Company sold its Canadian assets having a carrying value of $424.4 million. During 2006, the Company sold certain oil and gas properties in the deepwater Gulf of Mexico and all of its Argentine assets, which had carrying values of $430.6 million and $658.7 million, respectively, on their dates of sale. The results of operations of those properties have been reclassified as discontinued operations in accordance with SFAS 144 and, aside from costs incurred for oil and gas activities, are excluded from the geographic operating segment information provided below. See Note V for information regarding the Company's discontinued operations.

The following tables provide the Company's geographic operating segment data required by SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information," as well as results of operations of oil and gas producing activities required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities" as of and for the years ended December 31, 2008, 2007 and 2006. Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters" table column includes income and expenses that are not routinely included in the earnings measures internally reported to management on a geographic operating segment basis.

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	United States (in thousands)	South Africa	Tunisia	Other	Headquarters	Consolidated Total
Year ended December 31, 2008:						
Revenues and other income:						
Oil and gas	$ 1,943,131	$ 118,836	$ 215,383	$ —	$ —	$ 2,277,350
Interest and other	—	—	—	—	61,318	61,318
Gain (loss) on disposition of assets, net	513	—	—	—	(894)	(381)
	1,943,644	118,836	215,383	—	60,424	2,338,287
Costs and expenses:						
Oil and gas production	536,462	39,079	19,699	—	—	595,240
Depletion, depreciation and amortization	440,978	27,629	14,333	—	28,906	511,846
Impairment of oil and gas properties	104,269	—	—	—	—	104,269
Exploration and abandonments	197,758	143	37,629	—	—	235,530
General and administrative	—	—	—	—	141,823	141,823
Accretion of discount on asset retirement obligations	—	—	—	—	8,699	8,699
Interest	—	—	—	—	153,577	153,577
Hurricane activity, net	12,150	—	—	—	—	12,150
Minority interest in consolidated subsidiaries' net income	21,635	—	—	—	—	21,635
Other	—	—	—	—	127,065	127,065
	1,313,252	66,851	71,661	—	460,070	1,911,834
Income (loss) from continuing operations before income taxes	630,392	51,985	143,722	—	(399,646)	426,453
Income tax benefit (provision)	(233,245)	(15,076)	(86,490)	—	129,172	(205,639)
Income (loss) from continuing operations	$ 397,147	$ 36,909	$ 57,232	$ —	$ (270,474)	$ 220,814
Year ended December 31, 2007:						
Revenues and other income:						
Oil and gas	$ 1,552,780	$ 81,730	$ 106,341	$ —	$ —	$ 1,740,851
Interest and other	—	—	—	—	91,883	91,883
Gain (loss) on disposition of assets, net	844	—	—	—	(3,007)	(2,163)
	1,553,624	81,730	106,341	—	88,876	1,830,571
Costs and expenses:						
Oil and gas production	386,914	25,820	8,004	—	—	420,738
Depletion, depreciation and amortization	337,024	13,901	7,804	—	28,668	387,397
Impairment of oil and gas properties	5,687	—	—	20,528	—	26,215
Exploration and abandonments	231,638	276	16,743	30,672	—	279,329
General and administrative	—	—	—	—	129,587	129,587

Accretion of discount on asset retirement obligations	—	—	—	—	7,028	7,028
Interest	—	—	—	—	135,270	135,270
Hurricane activity, net	61,309	—	—	—	—	61,309
Minority interest in consolidated subsidiaries' net loss	(352)	—	—	—	—	(352)
Other	—	—	—	—	29,426	29,426
	1,022,220	39,997	32,551	51,200	329,979	1,475,947
Income (loss) from continuing operations before income taxes	531,404	41,733	73,790	(51,200)	(241,103)	354,624
Income tax benefit (provision)	(196,489)	(12,103)	(45,545)	—	141,492	(112,645)
Income (loss) from continuing operations	$ 334,915	$ 29,630	$ 28,245	$ (51,200)	$ (99,611)	$ 241,979

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	United States	South Africa	Tunisia	Other	Headquarters	Consolidated Total
Year ended December 31, 2006:						
Revenues and other income:						
Oil and gas	$1,302,029	$99,309	$57,602	$—	$ —	$ 1,458,940
Interest and other	—	—	—	—	43,498	43,498
Loss on disposition of assets, net	(451)	—	—	—	(6,008)	(6,459)
	1,301,578	99,309	57,602	—	37,490	1,495,979
Costs and expenses:						
Oil and gas production	324,049	21,795	3,222	—	—	349,066
Depletion, depreciation and amortization	276,921	9,455	4,007	—	23,698	314,081
Exploration and abandonments	172,859	7,516	14,616	55,205	—	250,196
General and administrative	—	—	—	—	116,595	116,595
Accretion of discount on asset retirement obligations	—	—	—	—	3,726	3,726
Interest	—	—	—	—	107,050	107,050
Hurricane activity, net	32,000	—	—	—	—	32,000