PIONEER NATURAL RESOURCES CO
Form 10-K
February 21, 2008

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, 2007

or

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

For the transition period from to

Commission File Number: 1-13245

Pioneer Natural Resources Company

(Exact name of registrant as specified in its charter)

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

Registrant’s telephone number, including area code: (972) 444-9001

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. **Yes** x **No 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	**$ 5,878,496,549**
Number of shares of Common Stock outstanding as of February 19, 2008	**119,389,995**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held during May 2008 — Referenced in Part III of this report.

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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," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company ("Pioneer" or the "Company") or its management 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. 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.
- *"LIBOR"* means London Interbank Offered Rate, which is a market rate of interest.
- *"LNG"* means liquefied natural gas.
- *"MBbl"* means one thousand Bbls.
- *"MBOE"* means one thousand BOEs.
- *"Mcf"* means one thousand cubic feet and is a measure of natural gas volume.
- *"MMBbl"* means one million Bbls.
- *"MMBOE"* means one million BOEs.
- *"MMBtu"* means one million Btus.
- *"MMcf"* means one million cubic feet.
- *"MMcfpd"* means one million cubic feet per day.
- *"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"* mean 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.

(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, 2007, the Company had 1,702 employees, 1,032 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 89 percent of the Company's proved oil and gas reserves as of December 31, 2007.

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. For the last several years the petroleum industry has generally been characterized by volatile oil, NGL and gas commodity prices. During recent years, 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, oil prices increased due to supply uncertainty surrounding Middle East conflicts and increasing world demand for both oil and refined products. A significant increase of refinery outages led to tightness in products markets which was responsible for oil price strength throughout much of the year. North American gas prices were generally consistent throughout 2007. Early 2007 price weakness, a result of a significant inventory overhang and mild weather, was largely offset by early fall when LNG imports to the Gulf Coast were reduced. LNG cargoes slated for delivery into the U.S. instead were sold into Asia and Europe in response to major demand increases brought on by harsh weather and large nuclear powered electric generation plant outages. Significant factors that will impact 2008 commodity prices include: developments in the issues currently impacting

Iraq and Iran and 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 continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals, including the impact of uncertain LNG deliveries to the United States. Perhaps the issue having the greatest impact on prices will be the strength of the U.S. economy and the prospect of a recession. In conjunction with the relatively higher commodity prices experienced during 2007, the Company also experienced increasing costs, particularly higher drilling and well servicing rig rates and drilling supplies.

To mitigate the impact of commodity price volatility on the Company's net asset value, Pioneer utilizes commodity hedge 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 2007, 2006 and 2005 from the Company's hedging activities and the Company's open hedge positions at December 31, 2007.

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, the Gulf of Mexico shelf, Mississippi 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, Mississippi 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, 2007, the Company's average daily production, on a BOE basis, increased eight percent as a result of successful drilling programs in the United States and Tunisia and a five percent decrease in the delivery of VPP volumes. Production, price and cost information with respect to the Company's properties for 2007, 2006 and 2005 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, 2007, the Company drilled 2,608 gross (2,415 net) wells, 96 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $4.2 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, 2007 include proved undeveloped reserves and proved developed reserves that are behind pipe of 221 MMBbls of oil and NGLs and 1,003 Bcf of gas. Development of these proved reserves will require future capital expenditures. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company's expected operating cash flows and the Company's financial condition. The Company believes that its current portfolio of proved reserves and unproved prospects provides attractive development and exploration opportunities for at least the next three to five years.

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. In 2008, the Company expects to spend approximately 90 percent of its $1.0 billion capital budget on low-risk development and resource play extension drilling in its four core onshore areas (Spraberry, Raton, Edwards Trend and Tunisia). The remaining ten percent will be focused primarily on development drilling in the Company's Alaskan Oooguruk project and Barnett Shale drilling. 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 2007, 2006 and 2005, the Company invested $536.7 million, $223.2 million and $272.9 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 2007, 2006 and 2005.

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, VPPs and discontinued operations during 2007, 2006 and 2005.

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 2007, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (14 percent), Oneok Resources (11 percent) and Occidental Energy Marketing, Inc. (11 percent). The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on its ability to sell its oil, NGL and gas production.

Hedging 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's hedging activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact on oil and gas revenues during 2007, 2006 and 2005 from commodity hedging activities and the Company's open and terminated commodity hedge positions at December 31, 2007.

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. Higher recent commodity prices have increased the cost of oil and gas properties available for acquisition. 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, 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

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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 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, 2007. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2008. 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.

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 at historically high levels and 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. Oil prices have recently been at historically high levels and gas prices have been at high levels over the past several years when compared to prior periods. 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, including those in the Middle East, Africa and South America;
- 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. A significant downward trend in commodity prices would have a material adverse effect on the Company's revenues, profitability and cash flow. 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 expectations, 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.

The Company's hedging activities could result in financial losses.

To reduce exposure to fluctuations in commodity prices, the Company has entered into, and expects in the future to enter into, hedging arrangements for a portion of its oil and gas production. These hedging arrangements may expose the Company to risk of financial loss in certain circumstances, including when:

- production is less than the hedged volumes;
- the counterparty to the hedging contract defaults on their contract obligations; or
- the hedging arrangements limit the benefit the Company would otherwise receive from increases in commodity prices.

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 2008. 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. If these trends continue in the future, they 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 write-down, as a noncash charge to earnings, the carrying value of the Company's oil and gas properties for impairments. The Company is required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of the Company's proved oil and gas properties. 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 require a write-down. 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, 2007, the Company carried unproved property costs of $277.5 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. 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. In addition, higher recent commodity prices have increased the cost of properties available for acquisition. The success of any acquisition will depend on a number of factors and involve potential risks, including among other things:

- the ability 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 Company periodically evaluates its goodwill for impairment, and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2007, the Company carried goodwill of $310.9 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 Company's assets and liabilities. If the fair value of the Company's net assets is not sufficient to fully support the goodwill balance, 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, 2007, the Company owned interests in four gas processing plants and ten treating facilities. The Company operates two of the gas processing plants and all ten 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 exploration 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.

Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of the risks described above, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance. Additionally, the Company relies to a large extent on facilities owned and operated by third-parties, and damage to or destruction of those third-party facilities could affect the ability of the Company to produce, transport and sell its hydrocarbons.

The Company may not be able to obtain access to pipelines, gas gathering, transmission 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, 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 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 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.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, 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, 2007 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" above for additional discussion regarding competition.

The Company's business depends to a significant extent upon the continued service and performance of key senior managers and technical personnel.

The Company's business depends to a significant extent upon the continued service and performance of a relatively small number of key senior managers and technical personnel. The loss of any existing key personnel, or the inability to attract, motivate and retain additional key personnel, could harm the Company's business, financial condition and results of operations.

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" above for additional discussion regarding government regulation.

The Company's international operations may be adversely affected by economic, political and other factors.

At December 31, 2007, 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 excusing performance, 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 reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to 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.

The Company may be unable to complete its plans to form a master limited partnership in the time expected, or at all, and the structure and terms of any master limited partnership could change materially from those anticipated.

In April, 2007, the Company announced an intention to form two new master limited partnerships, which would own interests in long-lived, low-decline oil and gas assets. Although the Company's subsidiary, Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest"), has filed a preliminary registration statement (subject to completion) with the SEC for an initial public offering of limited partner interests, the Company announced in February 2008 that the offering had been postponed due to market conditions. In addition to market conditions, the completion of the Company's plans to form the master limited partnerships is subject to numerous other risks beyond the control of the Company, and therefore it is possible that one or both of the master limited partnerships will not be formed, will not complete an offering of securities, will not raise the planned amount of capital even if an offering of securities is completed, and will not be able to complete its proposed actions. Furthermore, the structure, nature, purpose, proposed assets and liabilities, and proposed manner of offering of the master limited partnerships may change materially from those anticipated. In addition, the Company's retained investment in any master limited partnership formed would be subject to the risks normally attendant to businesses in the oil and gas exploration and production industry, including most of the same risks to which the Company is subject. The Company's announcement of its plan with respect to Pioneer Southwest's initial public offering did not, and this report does not, constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities of either master limited partnership will be made only in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note W of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for discussions of Pioneer Southwest's proposed initial public offering.

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, 2007, 2006 and 2005, which were located in the United States, Argentina, Canada, South Africa and Tunisia, were 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 86 percent, 89 percent and 82 percent of the Company's 2007, 2006 and 2005 proved reserves, respectively; and, 80 percent, 83 percent and 76 percent of the Company's 2007, 2006 and 2005 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 2007, 2006 or 2005 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 963.8 MMBOE, 904.9 MMBOE and 986.7 MMBOE at December 31, 2007, 2006 and 2005, respectively, representing $9.0 billion, $4.7 billion and $7.3 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, 2007 (in MBOE):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
United States	(35,715)	44,571	50,424	(227)	21,495
Canada	(2,950)	10,755	—	(35,712)	(3,210)
South Africa	(1,151)	—	—	—	(4,485)
Tunisia	(1,557)	24,478	—	(11,771)	3,880
Total	(41,373)	79,804	50,424	(47,710)	17,680

Production. Production volumes include 2,891 MBOE of field fuel and 2,950 MBOE of production associated with divested assets being presented as discontinued operations.

Extensions and discoveries. Extensions and discoveries are primarily the result of extension drilling in the Raton field and Spraberry field in the United States and the Horseshoe Canyon field in Canada and lower-risk exploratory drilling in the Company's South Texas Edwards Trend and Tunisian resource plays.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to bolt-on acquisitions in the Company's Spraberry oil field, Raton gas field and the entry into the Barnett Shale gas field.

Sales of minerals-in-place. Sales of minerals-in-place are principally related to the Company's divestiture of its Canadian assets and 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 20 MMBOE of positive price revisions offset by 2 MMBOE of negative technical revisions. The Company's proved reserves at December 31, 2007 were determined using year-end NYMEX equivalent prices of $95.92 per barrel of oil and $6.80 per Mcf of gas, compared to $60.82 per barrel of oil and $5.64 per Mcf of gas at December 31, 2006.

On a BOE basis, 62 percent of the Company's total proved reserves at December 31, 2007 were proved developed reserves. Based on reserve information as of December 31, 2007, and using the Company's production information for the year then ended, excluding production associated with divested assets included in discontinued operations, the reserve-to-production ratio associated with the Company's proved reserves was in excess of 20 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily sales volumes by geographic area as of and for the year ended December 31, 2007:

	Proved Reserves as of December 31, 2007				**2007 Average Daily Sales Volumes**		
	Oil & NGLs (MBbls) (in thousands)	**Gas (MMcf) (a)**	**MBOE**	**Standardized Measure**	**Oil & NGLs (Bbls)**	**Gas (Mcf) (b)**	**BOE**
United States	451,091	2,903,055	934,933	$ 8,265,557	37,196	316,418	89,933
South Africa	757	40,565	7,520	215,256	2,681	2,840	3,154
Tunisia	17,850	20,794	21,314	536,071	3,845	2,513	4,264
Total	469,698	2,964,414	963,767	$ 9,016,884	43,722	321,771	97,351

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(a) The gas reserves contain 290,599 MMcf of gas that will be produced and utilized as field fuel.
(b) The 2007 average daily sales volumes are from continuing operations and (i) do not include the field fuel produced, which averaged 47,526 Mcf per day, and (ii) were calculated using a 365-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, 2007 (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**
2008	4,050	$ 289,199	$ 34,854	$ 547,631	$ (293,286)
2009	9,439	591,900	98,272	741,023	(247,395)
2010	13,517	818,245	126,394	584,203	107,648
2011	16,954	998,665	168,585	565,725	264,355
2012	19,144	1,105,860	189,013	466,388	450,459
Thereafter	304,410	18,937,469	4,052,416	979,991	13,905,062
	367,514	$ 22,741,338	$ 4,669,534	$ 3,884,961	$ 14,186,843

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(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 since 2008.

Description of Properties

United States

Approximately 89 percent of the Company's proved reserves at December 31, 2007 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 2007:

	Development Drilling Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	10	350	350	—	10
Mid-Continent	1	—	1	—	—
Rocky Mountains	5	230	233	2	—
Onshore Gulf Coast	2	16	18	—	—
Total United States	18	596	602	2	10

	Exploration/Extension Drilling Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	1	1	1	—	1
Rocky Mountains	16	19	15	2	18
Onshore Gulf Coast	4	19	19	1	3
Barnett Shale	—	6	6	—	—
Alaska	—	3	—	2	1
Total United States	21	48	41	5	23

The following table summarizes the Company's United States costs incurred by geographic area during 2007:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in thousands)					
Permian Basin	$ 56,232	$ 61,546	$ 23,395	$ 422,158	$ 2,987	$ 566,318
Mid-Continent	314	—	47	21,436	(951)	20,846
Rocky Mountains	164,730	43,502	71,467	180,340	29,813	489,852
Onshore Gulf Coast	6,367	6,364	148,756	140,130	1,507	303,124
Barnett Shale	99,133	87,788	23,351	—	1,320	211,592
Alaska	—	1,554	68,993	260,848 (a)	(218)	331,177
Gulf of Mexico						
Continuing operations	—	13	(1,269)	4,893	(1,315)	2,322
Discontinued operations	—	—	745	354	—	1,099
Total United States	$ 326,776	$ 200,767	$ 335,485	$ 1,030,159	$ 33,143	$ 1,926,330

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(a) Includes $22.0 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 has started completing 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 enhance 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 July 2007, the Company entered into an agreement under which the Company has the option to purchase an additional 22 percent interest in the Spraberry Midkiff-Benedum gas processing system for $230 million, subject to normal closing adjustments. The additional 22 percent can be purchased in 2008 and 2009 and, if exercised, will increase the Company's interest in the system to 49 percent. In conjunction with this transaction, the Company extended its percent of proceeds ("POP") contract with the plant to 2022 and negotiated incremental increases in the Company's POP beginning in 2009.

In December 2007, the Company acquired approximately 44,000 gross acres in the Spraberry field for $89.4 million, with Pioneer being operator of the acquired properties. Proved reserves associated with the acquisition are approximately 15 MMBOE. The Company estimates that the acquisition provides more than 600 potential drilling locations utilizing 40-acre spacing.

During 2007, the Company (a) drilled 350 wells, an increase of over 17 percent compared to 2006, (b) acquired approximately 185,000 gross acres, bringing its total acreage position to approximately 869,000 gross acres (688,000 net acres), (c) completed several bolt-on property acquisitions and joint ventures and (d) successfully drilled a majority of the wells to the Wolfcamp formation. The Company plans to drill approximately 350 wells in 2008 and continue to pursue acreage expansions and bolt-on acquisitions.

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. Such 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 pilot program has been initiated and the Company is monitoring its production performance. To capitalize on these rule changes, future completion designs are being developed and continued optimization is planned 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 / gathering system efficiency. As part of this effort, approximately 17 miles of 16 inch pipeline was recently replaced in the heart of the field. The Company received regulatory relief in parts of the West Panhandle field to allow for future infill drilling locations.

Rocky Mountains

Raton field. The Raton Basin properties are located in the southeast portion of Colorado. Exploration for CBM in the Raton Basin began in the late 1970s and continued through the late 1980s, with several companies drilling and testing more than 100 wells during this period. The absence of a pipeline to transport gas from the Raton Basin prevented full scale development until January 1995, when Colorado Interstate Gas Company completed the construction of the Picketwire lateral pipeline system. The Company's gas in the Raton Basin has an average energy content of 1,000 Btu. 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 owns the majority of the well servicing and frac equipment that it utilizes in the Raton field to control costs and insure availability. In the Raton field, the Company sells its gas at a Mid-Continent index price which historically has generally provided higher realized gas prices as compared to the Rockies-based indexes.

In December 2007, the Company acquired approximately 30,000 net acres in the Raton Basin for $205.3 million. The acquired acreage has approximately 95 Bcf of proved reserves.

During 2007, the Company (a) drilled 230 wells, and put 301 wells on production, (b) added wellhead compression and (c) continued efforts to optimize gathering and compression facilities. During 2008, the Company expects to complete approximately 175 wells.

Piceance/Uinta Basins. The Piceance Basin is located in the central portion of western Colorado, and the Uinta Basin is located in the central portion of eastern Utah. The Company owns approximately 244,000 gross acres covering producing and prospective regions of the Piceance and Uinta Basins. Currently, production is established from various tight sandstone, coal and shale formations. The Company's significant projects in the area are CBM plays at Columbine Springs and Castlegate and a deep gas play at Main Canyon.

Sand Wash Basin. The Sand Wash Basin is the site of a potential CBM project located north of the Company's Piceance Basin properties. The Company holds a 50 percent operated interest in 114,000 gross acres in the Lay Creek field. At Lay Creek, the Company has drilled 18 wells in six separate pilot areas and completed workovers and recompletions on 14 wells drilled by a previous operator. The Company completed the water treatment facilities and initiated sales of production in 2007. Determination of success of the pilot project is dependent on the ability to dewater the formation and determine if commercial quantities of gas can be produced. The pilot project is currently in the dewatering phase and a determination of commerciality should be known by the end of 2008.

Gas prices. In general, industry drilling success in the Rocky Mountains area (which affects the Company's properties in the Piceance/Uinta Basins and Sand Wash Basin) has created more supply than can be transported by the currently available pipeline infrastructure. As a result, gas prices in the region have experienced greater volatility and at the end of the third quarter of 2007 spot gas prices for the area were approximately $.60 per MMBtu. As a result of the extremely low gas prices during September and October of 2007, the Company shut-in approximately 5 to 6 MMcfpd of gas production in the Uinta/Piceance area. Additional pipeline capacity was added in the first quarter of 2008 with the start-up of the Rockies Express pipeline, which should alleviate the capacity constraints, allowing more gas to reach consumer markets at improved price levels. Prices have rebounded in the area since September 30, 2007 and the Company believes that gas prices will continue to improve as a result of the Rockies Express pipeline being in service.

Onshore Gulf Coast

South Texas. In 2007, the South Texas drilling program focused on the Edwards Trend, a tight gas limestone reservoir characterized by narrow bands of dry gas fields extending over 250 miles in length. The Company's drilling activity occurred in both established areas such as Pawnee field and growth areas along the Trend. To date the Company has acquired over 305,000 gross acres in the Edwards Trend. In addition to the Pawnee field, the Company has operations in the SW Kenedy, Sawfish, Word, Three Rivers and Washburn fields. Production depths in the Edwards Trend range from 9,500 feet to 14,500 feet.

During 2007, the Company drilled 20 exploration and appraisal wells targeting new field discoveries in the Edwards Trend growth areas with 100 percent success, exceeding expectations and increasing proved gas reserves. Nine of these new wells have been added to production, three wells are awaiting pipelines or testing, four are awaiting stimulation, and four are waiting on the horizontal lateral portion of the well to be completed. In previously established areas, including the Pawnee field, 14 wells were drilled with 100 percent success.

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. To expand its 3-D data coverage to include new discoveries and additional prospects, the Company is in the process of shooting and interpreting approximately 900 square miles of new data. Multiple surveys were completed in 2007 and more are planned for 2008.

In order to accommodate its rapidly growing Edwards Trend production, the Company significantly expanded its existing gas gathering and processing infrastructure during 2007. The expansion included over 30 miles of gathering system and three additional treating facilities were installed.

In 2008, the Company expects a comparable drilling program to that in 2007. Also planned are additional facilities expansions to accommodate increasing production.

Mississippi. The Company has built an acreage position covering multiple plays in the Mississippi Salt Basin and now holds leases and option interests covering approximately 150,000 net acres. Over the next two to three years, the Company expects to test a number of opportunities and to continue technical work that is currently underway.

The Company drilled two successful Cotton Valley wells in the Bolton field and installed a gas treating facility to process the gas. The Company is permitting for a 3-D seismic shoot in 2008 for the Bolton field to better define the resource potential and future drilling plans.

Barnett Shale

During 2007, the Company participated in the drilling of six successful exploration wells on its approximate 9,300 gross acres in the Barnett Shale play that it acquired in the second quarter of 2007.

In December 2007, the Company expanded its Barnett Shale acreage position by completing a $144.3 million acquisition. The Company estimates proved reserves on the acreage to be approximately 13.5 MMBOE. The acreage being acquired contains more than 300 potential drilling locations, with most locations covered by 3-D seismic data.

The Company's total holdings in the Barnett Shale play now approximate 80,000 gross acres, with more than 450 potential drilling locations. The Company plans to drill 20 wells in 2008 with the expectation of increasing its drilling program in 2009.

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 the 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 approximately 40 horizontal development and injector wells in December of 2007. The Company estimates that first production will occur during the first half of 2008 and that first sales will occur mid-year 2008. During 2008, the Company expects to drill 13 to 15 of the 40 planned 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 a lateral sidetrack from an existing wellbore at an onshore site to further appraise the resource potential of the unit. The initial unstimulated production test results were encouraging. The Company plans to begin permitting activities and continue facilities planning during 2008 for a future potential development of the project and to drill another appraisal well in 2009.

Onshore North Slope area. During the 2006-2007 winter drilling season, the Company participated in drilling two exploratory wells in the National Petroleum Reserve - Alaska ("NPRA") area, both of which were noncommercial.

Gulf of Mexico

Gulf of Mexico area. During 2005, the Company announced a discovery on its Clipper prospect in the Green Canyon Blocks 299 and 300 in the deepwater Gulf of Mexico. During 2006, the Company drilled two successful Clipper appraisal wells, but drilled an unsuccessful exploratory well at the Flying Cloud prospect, a prospect near the Clipper discovery. The Company began evaluation plans for the potential development of the discovery, but projected capital costs for the project doubled during the evaluation, which resulted in the Company electing to not pursue the development of the Clipper project. Accordingly, the Company recognized an exploration and abandonment charge of $72.1 million in the fourth quarter of 2007.

As a result of Hurricane Rita, the Company's East Cameron facility, located on the Gulf of Mexico shelf, was destroyed. Operations to reclaim and abandon the East Cameron facility began in 2007. During the second quarter of 2007, the Company increased the estimated cost to reclaim and abandon the East Cameron facility by $66.0 million to an aggregate estimated cost of $185 million. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis prepared by a third-party engineering firm for the majority of the work, an estimate by the Company for the remaining work that was not covered by the third-party analysis and actual abandonment activity to date. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the East Cameron 322 facility.

International

The Company's international operations are located offshore South Africa and onshore in southern Tunisia. Additionally, the Company has an exploration permit in Equatorial Guinea. During 2007, the Company also disposed of its interests in Block 320 in Nigeria, and relinquished its remaining interest in Block 256 in Nigeria due to unsuccessful exploratory drilling results. The Company is currently winding up its efforts to exit Nigeria completely. In November 2007, the Company closed the sale of all of the Company's common stock in its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. See Notes N, S and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Nigerian and Canadian divestitures. As of December 31, 2007, approximately three percent of the Company's proved reserves were located in Africa.

The following tables summarize the Company's international development and exploration/extension drilling activities during 2007:

Development Drilling

	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Canada	3	—	1	1	1	—
South Africa	2	1	3	—	—	—
Total International	5	1	4	1	1	—

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	Exploration/Extension Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Canada	16	17	7	6	20	—
Tunisia	5	12	12	4	—	1
West Africa - Nigeria	—	1	—	1	—	—
Total International	21	30	19	11	20	1

The following table summarizes the Company's international costs incurred by geographic area during 2007:

	Property Acquisition Costs		Exploration	Development	Asset Retirement	
	Proved	Unproved	Costs	Costs	Obligations	Total
	(in thousands)					
Canada – discontinued operations	$ 82	$ 3,620	$ 32,160	$ 63,450	$ 1,134	$ 100,446
South Africa	—	—	276	113,591 (a)	(2,413)	111,454
Tunisia	—	718	103,381	9,724	1,265	115,088
Other	—	—	5,149	—	—	5,149
West Africa:						
Equatorial Guinea	—	—	704	—	—	704
Nigeria	—	—	18,052	—	—	18,052
Total International	$ 82	$ 4,338	$ 159,722	$ 186,765	$ (14)	$ 350,893

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(a) Includes $10.5 million of capitalized interest related to the South Coast Gas project.

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 the majority of the gas from the field has been reinjected. The Company has a 40 percent working interest in 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 all 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. During 2007, two additional wells were drilled and installation of pipeline and facilities infrastructure was completed as part of the South Coast Gas project. First production from the South Coast Gas project was achieved in the third quarter of 2007 at approximately 15 to 20 MMcfpd (gross). It is expected that the simultaneous production of both oil and gas from the Sable field will increase the ultimately recoverable oil reserves.

A significant portion of the gas reserves associated with the South Coast Gas project is in the Sable field. Initially, the gas production from the Sable field was not expected to commence until the oil production was completed. However, as a result of production performance from the Sable field and improved oil prices, which have had the effect of extending the economic life of the Sable oil field, facilities modifications are being planned that would allow for the simultaneous production of oil and gas from the Sable field. The modifications are currently expected to be completed in late 2008 or early 2009.

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 11,900 square kilometers containing two production concessions targeting the Acacus formation with additional future upside exploration potential from this and other formations.

- **Jenein Nord Permit and Cherouq Concession.** The Jenein Nord Permit covers approximately 1,200 square kilometers. Over the past two years, the Company has conducted an intensive exploration program over the area. As a result of an aggressive 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. During 2007, the Company drilled seven exploration wells and first production from the concession was achieved in late fourth quarter 2007.

The Company plans to drill up to seven additional wells and acquire an additional 295 square kilometers of 3-D seismic data over the Cherouq Concession during 2008.

- **Borj El Khadra Permit and Adam Concession.** The Borj El Khadra Permit, including the Adam Concession, covers approximately 2,900 square kilometers. Production from the Adam Concession began in May 2003, for which the Company now has a 20 percent working interest. During 2007, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling four wells, of which all were successful, and completed drilling of two wells in the Borj El Khadra Permit, of which one was successful. The Company plans to drill an additional four wells in the Adam Concession and two wells in the Borj El Khadra exploration permit during 2008.

- **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 2007, the Company completed the acquisition of 310 kilometers of seismic data and began processing the data. Processing and interpretation of the seismic data is scheduled to be completed during the second quarter of 2008. The Company anticipates drilling an exploration well in the second half of 2008.

- **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. The Company intends to acquire an additional 900 square kilometers of 3-D seismic data and expects to drill up to two exploration wells in the second half of 2008.

Equatorial Guinea. The Company owns a 50 percent interest in Block H in deepwater Equatorial Guinea, which covers over 240,000 acres. In late 2006, the Republic of Equatorial Guinea ratified a new hydrocarbons law, which among other things, appears to entitle Equatorial Guinea to increase substantially its carried interest in all concessions, including Block H. In addition, drilling costs have increased significantly beyond those originally anticipated. Given these and other facts, the Company and the other participants in the block have been unable to reach an agreement as to their respective rights and obligations under a joint operating agreement relating to the well operations in the block and as a result, the parties have commenced arbitration. In connection with the ongoing arbitration among the parties, the Company recognized an impairment charge of approximately $10.3 million to write off its remaining basis in Block H. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's arbitration associated with Block H.

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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, 2007, 2006 and 2005. 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 2007, 2006 and 2005. 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, 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	$ 6.54	$ 22.43	$ 3.46	$ 6.91

Third-party transportation charges	0.97	—	1.57	0.97
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	$ 5.64	$ 14.47	$ 1.99	$ 5.94
Third-party transportation charges.	0.81	—	1.42	0.79
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

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2005			
	United States	South Africa	Tunisia	Total
Production information:				
Annual sales volumes:				
Oil (MBbls)	8,008	2,405	1,269	11,682
NGLs (MBbls)	6,352	—	—	6,352
Gas (MMcf)	98,927	—	—	98,927
Total (MBOE)	30,849	2,405	1,269	34,523
Average daily sales volumes:				
Oil (Bbls)	21,942	6,588	3,477	32,007
NGLs (Bbls)	17,403	—	—	17,403
Gas (Mcf)	271,033	—	—	271,033
Total (BOE)	84,517	6,588	3,477	94,582
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 32.01	$ 53.01	$ 52.98	$ 38.61
NGL (per Bbl)	$ 31.72	$ —	$ —	$ 31.72
Gas (per Mcf)	$ 6.94	$ —	$ —	$ 6.94
Revenue (per BOE)	$ 37.09	$ 53.01	$ 52.98	$ 38.78
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 54.05	$ 53.01	$ 52.98	$ 53.72
NGL (per Bbl)	$ 31.72	$ —	$ —	$ 31.72
Gas (per Mcf)	$ 7.26	$ —	$ —	$ 7.26
Revenue (per BOE)	$ 43.86	$ 53.01	$ 52.98	$ 44.84
Average costs (per BOE):				
Production costs:				
Lease operating	$ 4.55	$ 11.79	$ 1.66	$ 4.95
Third-party transportation charges	0.66	—	1.54	0.64
Taxes:				
Ad valorem	1.31	—	—	1.17
Production	1.94	—	—	1.73
Workover	0.53	—	—	0.48
Total	$ 8.99	$ 11.79	$ 3.20	$ 8.97
Depletion expense	$ 7.10	$ 10.19	$ 3.75	$ 7.19

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, 2007, 2006 and 2005:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
As of December 31, 2007:						
United States	5,498	4,825	10,323	4,362	4,213	8,575
South Africa	3	5	8	1	2	3
Tunisia	13	—	13	3	—	3
Total	5,514	4,830	10,344	4,366	4,215	8,581
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
As of December 31, 2005:						
United States	4,552	4,028	8,580	3,606	3,695	7,301
Argentina	821	261	1,082	684	202	886
Canada	65	675	740	30	511	541
South Africa	8	—	8	2	—	2
Tunisia	4	—	4	2	—	2
Total	5,450	4,964	10,414	4,324	4,408	8,732

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(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, 2007, the Company owned interests in seven 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, 2007:

LEASEHOLD ACREAGE

Developed Acreage	Undeveloped Acreage	Royalty

	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
United States:					
Onshore	1,414,288	1,209,915	2,782,979	1,446,940	294,908
Offshore	61,840	23,334	85,142	72,739	6,750
	1,476,128	1,233,249	2,868,121	1,519,679	301,658
South Africa	119,579	53,281	3,508,421	1,578,790	—
Tunisia	287,540	80,044	2,860,487	1,569,116	—
West Africa	—	—	244,881	122,441	—
Total	1,883,247	1,366,574	9,481,910	4,790,026	301,658

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2007:

	Acres Expiring (a)	
	Gross	**Net**
2008 (b)	1,026,197	556,110
2009	1,914,820	1,087,405
2010	1,230,688	666,252
2011	272,400	227,596
2012	133,499	93,894
Thereafter	4,904,306	2,158,769
Total	9,481,910	4,790,026

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

(b) Acres subject to expiration during 2008 include 827,308 gross acres (201,341 net acres) in Tunisia and 198,889 gross acres (153,427 net acres) in North America. In Tunisia, the Company has received extensions, plans to make the necessary expenditures to extend the acreage or intends to seek extensions on the 2008 expirations. As to the remaining acreage, the Company may extend the leases prior to their expiration based upon 2008 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 2007, 2006 and 2005. 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,		
	2007	2006	2005	2007	2006	2005
United States:						
Productive wells:						
Development	602	662	537	581	619	505
Exploratory	41	52	40	33	42	37
Dry holes:						
Development	2	8	7	2	7	7
Exploratory	5	8	7	3	6	5
	650	730	591	619	674	554
Argentina:						
Productive wells:						
Development	—	14	65	—	14	64
Exploratory	—	4	19	—	4	18
Dry holes:						
Development	—	1	4	—	1	4
Exploratory	—	2	14	—	2	14
	—	21	102	—	21	100
Canada:						
Productive wells:						
Development	1	2	27	1	2	26
Exploratory	7	326	87	5	297	72
Dry holes:						
Development	1	—	—	—	—	—
Exploratory	6	16	7	5	15	7
	15	344	121	11	314	105
South Africa:						
Productive wells:						
Development	3	2	—	1	1	—
Exploratory	—	—	1	—	—	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	—	1	—	—	1	—
	3	3	1	1	2	—
Tunisia:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	12	2	2	8	1	1
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	4	2	2	3	—	1
	16	4	4	11	1	2
West Africa:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	—	—	—	—	—	—

Dry holes:						
Development	—	—	—	—	—	—
Exploratory	1	1	1	—	—	—
	1	1	1	—	—	—
Total	685	1,103	820	642	1,012	761
Success ratio (a)	97 %	95 %	85 %	98 %	95 %	84 %

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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.

The following table sets forth information about the Company's wells upon which drilling was in progress as of December 31, 2007:

	Gross Wells	Net Wells
United States:		
Development	10	9
Exploratory	23	14
	33	23
Tunisia:		
Exploratory	1	1
Total	34	24

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 2007.

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 $.27 per share and $.25 per share during each of the years ended December 31, 2007 and 2006, respectively. On February 12, 2008, the Board declared a $.14 per share dividend to the holders of the Company's common stock on March 31, 2008.

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, 2007 and 2006:

	High	Low	Dividends Declared Per Share
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
Year ended December 31, 2006			
Fourth quarter	$ 44.46	$ 36.48	$ —
Third quarter	$ 46.70	$ 37.07	$ 0.13
Second quarter	$ 46.75	$ 36.43	$ —
First quarter	$ 54.46	$ 37.98	$ 0.12

On February 15, 2008, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $43.94 per share.

As of February 15, 2008, the Company's common stock was held by approximately 25,000 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, 2007:

Period	**Total Number of Shares (or Units) Purchased (a)**	**Average Price Paid per Share (or Unit)**	**Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs**	**Approximate Dollar Amount of Shares That May Yet Be Purchased Under Plans or Programs**
October 2007	113,873	$ 44.97	110,400	
November 2007	28,696	$ 44.43	—	
December 2007	5,952	$ 46.74	—	
Total	148,521	$ 44.94	110,400	$ 537,216,725

(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 2007, the Company purchased $212.8 million 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, 2007 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)				
	2007	2006	2005	2004	2003
	(in millions, except per share data)				
Statements of Operations Data:					
Revenues and other income:					
Oil and gas	$ 1,740.9	$ 1,458.9	$ 1,338.9	$ 962.2	$ 675.8
Interest and other (b)	94.6	48.4	26.4	1.8	7.0
Gain (loss) on disposition of assets, net	(2.2)	(6.5)	60.1	0.3	1.4
	1,833.3	1,500.8	1,425.4	964.3	684.2
Costs and expenses:					
Oil and gas production	420.7	349.1	309.7	206.1	145.7
Depletion, depreciation and amortization	387.4	314.1	267.8	208.3	149.2
Impairment of long-lived assets (c)	26.2	—	0.6	39.7	—
Exploration and abandonments	279.3	250.2	153.8	94.3	77.8
General and administrative	129.6	116.6	110.1	69.5	51.1
Accretion of discount on asset retirement obligations	7.0	3.7	3.3	3.6	2.6
Interest	135.3	107.0	126.0	102.0	91.1
Hurricane activity, net (d)	61.3	32.0	39.8	—	—
Other (e)	31.9	36.9	80.8	25.5	11.3
	1,478.7	1,209.6	1,091.9	749.0	528.8
Income before continuing operations before income taxes and cumulative effect of changes in accounting principle	354.6	291.2	333.5	215.3	155.4
Income tax benefit (provision) (f)	(112.6)	(141.0)	(149.2)	(62.1)	134.2
Income from continuing operations before cumulative effect of change in accounting principle	242.0	150.2	184.3	153.2	289.6
Income from discontinued operations, net of tax (a)	130.7	589.5	350.3	159.7	105.6
Income before cumulative effect of change in accounting principle	372.7	739.7	534.6	312.9	395.2
Cumulative effect of change in accounting principle, net of tax (g)	—	—	—	—	15.4
Net income	$ 372.7	$ 739.7	$ 534.6	$ 312.9	$ 410.6
Income from continuing operations before cumulative effect of change in accounting principle per share:					
Basic	$ 2.01	$ 1.21	$ 1.35	$ 1.22	$ 2.47
Diluted	$ 1.99	$ 1.19	$ 1.32	$ 1.21	$ 2.44
Net income per share:					
Basic	$ 3.10	$ 5.95	$ 3.90	$ 2.50	$ 3.50
Diluted	$ 3.06	$ 5.81	$ 3.80	$ 2.46	$ 3.46
Weighted average shares outstanding:					
Basic	120.2	124.4	137.1	125.2	117.2
Diluted	121.7	127.6	141.4	127.5	118.5

Dividends declared per share	$ 0.27	$ 0.25	$ 0.22	$ 0.20	$ —
Balance Sheet Data (as of December 31):					
Total assets	$ 8,617.0	$ 7,355.4	$ 7,329.2	$ 6,733.5	$ 3,951.6
Long-term obligations and minority interests	$ 4,580.1	$ 3,483.7	$ 4,078.8	$ 3,357.2	$ 1,762.0
Total stockholders' equity	$ 3,042.7	$ 2,984.7	$ 2,217.1	$ 2,831.8	$ 1,759.8

(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 2007 includes $74.9 million 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 2006 and 2005 include $7.6 million and $14.2 million, respectively, of income associated with various business interruption insurance claims. See Notes M and U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(c) 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 2007, 2006 and 2005 includes $66.0 million, $75.0 million and $39.8 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) Other expense for 2007 and 2006 included $8.7 million and $.3 million of idle drilling equipment costs, respectively, resulting from unused contract commitments. Other expense for 2006, 2005 and 2003 includes losses on the early extinguishment of debt of $8.1 million, $26.5 million and $1.5 million, respectively. Other expense for 2007, 2006, 2005, 2004 and 2003 includes $2.1 million, $(10.6) million, $29.8 million, $4.2 million and $2.8 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".

(f) Income tax benefit for 2003 includes a $197.7 million adjustment to reduce United States deferred tax asset valuation allowances.

(g) Cumulative effect of change in accounting principle for 2003 relates to the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003.

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 2007 included the following highlights:

- As a result of the gain recognized on the sale of deepwater Gulf of Mexico and Argentine assets during 2006, partially offset by the gain recognized on the Canadian divestiture in 2007, net income decreased 50 percent to $372.7 million ($3.06 per diluted share) in 2007 from $739.7 million ($5.81 per diluted share) in 2006.

- Income from continuing operations increased to $242.0 million ($1.99 per diluted share) for 2007, as compared to $150.2 million ($1.19 per diluted share) for 2006, primarily due to higher oil and gas revenues.

- Average daily sales volumes, on a BOE basis, increased eight percent in 2007 as compared to 2006, primarily due to successful drilling programs and a five percent decrease in the delivery of VPP volumes.

- Oil and gas revenues increased $281.9 million, or 19 percent in 2007, as compared to 2006, due to a combination of increased production and increases in worldwide commodity prices.

- The Company completed the divestiture of the Company's Canadian subsidiary for net proceeds of $525.7 million, resulting in a gain of $101.3 million.

- The Company recognized income from discontinued operations of $130.7 million ($1.07 per diluted share) during 2007, primarily attributable to the sale of Canadian assets, as compared to income from discontinued operations of $589.5 million ($4.62 per diluted share) during 2006, which included the sale of the deepwater Gulf of Mexico and Argentine assets.

- Net cash provided by operating activities increased by $20.5 million, or three percent as compared to that of 2006, primarily due to increased sales volumes, increased commodity prices and $74.9 million of income realized from the disposal of Alaskan PPT credits, offset by the cash provided by operating activities associated with the 2006 deepwater Gulf of Mexico and Argentine asset dispositions and the 2007 disposal of the Canadian assets.

- The Company added 147.9 MMBOE of proved reserves during 2007, resulting in total proved reserves of 963.8 MMBOE at December 31, 2007.

- The Company commenced production at the South Coast Gas Project in South Africa late in the third quarter of 2007.

- The construction and installation of facilities at the Company's Alaskan Oooguruk project was completed and drilling was initiated in December 2007 with first production on schedule for the first half of 2008, with first sales expected mid 2008.

- The Company acquired oil and gas properties that complemented the Company's exploration and development drilling activities with significant acquisitions in the Spraberry field, Raton field and the Barnett Shale play of approximately $439 million.

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2008 Outlook and Activities

Commodity prices. Significant factors that may impact future commodity prices include: developments in the issues currently impacting Iraq and Iran and the Middle East in general; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals, including the impact of weather conditions and increasing LNG deliveries to the United States. Although the Company cannot predict the occurrence of events that may affect future 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. From time to time, Pioneer expects that it may hedge a portion of its commodity price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues. 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 commodity hedge positions at December 31, 2007. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

Capital budget for 2008. The Company announced a 2008 capital budget of $1.0 billion, excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs. The 2008 capital budget is significantly less than 2007 capital spending levels, excluding acquisitions, due to the completion of facilities construction for both the South Coast Gas project off the coast of South Africa and the Oooguruk project on the North Slope of Alaska, the sale of all Canadian assets and the elimination of higher-risk exploration. Approximately 90 percent of the 2008 capital budget will be focused on low-risk development drilling and resource play extensions in Pioneer's four core onshore areas (Spraberry, Raton, Edwards Trend and Tunisia). The remaining ten percent will be focused primarily on development drilling in the Oooguruk project and Barnett Shale drilling. For 2008, the Company currently expects that cash flows from operations will be sufficient to fund the $1.0 billion capital budget.

2008 Annual Production. The Company believes that the results from its 2007 drilling program and 2008 capital budget will allow the Company to realize production growth per share during 2008 of 12 percent or more as compared to the Company's 2007 production per share.

First Quarter 2008 Outlook. Based on current estimates, the Company expects that first quarter 2008 production will average 103,000 to 109,000 BOEPD. The range reflects the typical variability in the timing of oil cargo shipments in South Africa and Tunisia.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $11.75 to $12.75 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 $10.75 to $11.75 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $40 million to $70 million including (i) up to $40 million from activities in the Company's resource plays in the Edwards Trend in South Texas, the Rockies area and Tunisia and (ii) up to $30 million in seismic investments and personnel costs, primarily in the Edwards Trend and Tunisia resource plays. General and administrative expense is expected to be $32 million to $36 million. Interest expense is expected to be $35 million to $40 million. Accretion of discount on asset retirement obligations is expected to be $2 million to $3 million.

The Company's first quarter effective income tax rate is expected to range from 40 percent to 45 percent based on current capital spending plans and higher tax rates in certain foreign jurisdictions. Cash income taxes are expected to range from $10 million to $15 million, principally related to Tunisian income taxes.

Pioneer Southwest Energy Partners L.P. Initial Public Offering. On January 8, 2008, Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest"), a subsidiary of the Company, filed an amendment to its registration statement (subject to completion) with the SEC to sell limited partner interests. If the offering is completed, Pioneer Southwest would own interests in certain oil and gas properties currently owned by the Company in the Spraberry field in the Permian Basin of West Texas. Pioneer Southwest's registration statement contemplates an offering of 7,500,000 common units representing a 35.3 percent limited partner interest in Pioneer Southwest. Upon completion of this offering, the Company would own a 0.1 percent general partner interest and a 64.6 percent limited partner interest in Pioneer Southwest. The underwriters would be granted a 30-day option to purchase up to 1,125,000 additional common units. The Company's limited partner interest would be reduced to 61.4 percent if the underwriters exercise their over-allotment option in full. Assuming an initial public offering price of $20.00 per common unit and that the underwriters exercise their over-allotment option, estimated gross proceeds from the offering would be $150 million. In February 2008, the Company announced that the initial public offering of common units of Pioneer Southwest has been postponed due to market conditions and timing of the offering remains uncertain. There can be no assurance that Pioneer Southwest will complete the offering, or if completed, that the offering will be structured as described above.

This report shall not constitute an offer to sell or the solicitation of an offer to buy any securities of Pioneer Southwest. Any offers, solicitations of offers to buy, or any sales of securities of Pioneer Southwest will be made only in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom.

Acquisitions

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 were primarily bolt-on and acreage acquisitions in the Spraberry field and Edwards Trend area. In North America, the acquisition of unproved properties is 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.

2005 acquisition expenditures. During 2005, the Company spent approximately $272.9 million to acquire proved and unproved properties, which was comprised of approximately $173.4 million of proved properties and approximately $99.5 million of unproved properties.

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.

Nigeria. In prior years, a subsidiary of the Company joined other companies in a production sharing contract covering the oil prospecting license for Block 320 in deepwater Nigeria, gaining exploration rights from the Nigerian National Petroleum Corporation. During the third quarter of 2007, the Company disposed of all its shares in the subsidiary holding Block 320. As a result of the disposition of the shares in the Nigerian subsidiary, the Company no longer owns any interest in Block 320 and will not fund or participate in any future operations in connection with Block 320.

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.

Volumetric production payments. During 2005, the Company sold 27.8 MMBOE of proved reserves in the Hugoton and Spraberry fields, by means of three VPPs for net proceeds of $892.6 million, including the assignment of the Company's obligations under certain derivative hedge agreements.

The Company's VPPs represent limited-term overriding royalty interests in oil and gas reserves that: (i) entitle the purchaser to receive production volumes over a period of time from specific lease interests; (ii) are free and clear of all associated future production costs and capital expenditures; (iii) are nonrecourse to the Company (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser and (v) allows the Company to retain the remaining reserves after the VPPs volumetric quantities have been delivered. Based on the scheduled production deliveries, the multiple VPPs are scheduled to be completed between 2009 and 2012.

Canada and Shelf Gulf of Mexico. During 2005, the Company sold its interests in the Martin Creek and Conroy Black areas of northeast British Columbia and the Lookout Butte area of southern Alberta for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During 2005, the Company also sold all of its interests in certain oil and gas properties on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 million. The historic results of these properties and the related gains on disposition are reported as discontinued operations.

Gabon divestiture. In 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owns the interest in the Olowi block for $47.9 million of net proceeds, resulting in a gain of $47.5 million with no associated income tax effect either in Gabon or the United States. During 2007, Pioneer relinquished its rights to receive additional payments for production discovered from deeper reservoirs on the block in consideration for a release of certain obligations.

Results of Operations

Oil and gas revenues. Oil and gas revenues totaled $1.7 billion, $1.5 billion and $1.3 billion during 2007, 2006 and 2005, respectively. 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 volumetric production payment ("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 field and the timing of oil cargo liftings, partially offset by increases in average reported oil prices and initial gas production from the South Coast Gas project. The revenue increase during 2006, as compared to 2005, was due to a 70 percent increase in reported oil prices and an 11 percent increase in NGL prices. Partially offsetting the effects of increased oil and NGL prices was an 11 percent decrease in reported gas prices and a four percent decrease in average daily sales volumes on a BOE basis.

A significant factor contributing to the increases in reported oil prices and decreases in reported oil sales volumes in 2006 as compared to 2005 was the initiation of first deliveries of oil volumes under the Company's VPP agreements in January 2006. VPP gas deliveries were initiated during February 2005 and declined by three percent during 2006, as compared to that of 2005. In accordance with GAAP, VPP deliveries result in VPP deferred revenue amortization being recognized in oil and gas revenues with no associated sales volumes being recorded.

The following table provides average daily sales volumes from continuing operations by geographic area and in total, for 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
Oil (Bbls):			
United States	18,643	17,716	21,942
South Africa	2,681	4,127	6,588
Tunisia	3,845	2,386	3,477
Worldwide	25,169	24,229	32,007
NGLs (Bbls):			
United States	18,553	18,488	17,403
Gas (Mcf):			
United States	316,418	284,732	271,033
South Africa	2,840	—	—
Tunisia	2,513	1,195	—

Worldwide	321,771	285,927	271,033
Total (BOE):			
United States	89,933	83,659	84,517
South Africa	3,154	4,127	6,588
Tunisia	4,264	2,585	3,477
Worldwide	97,351	90,371	94,582

On a BOE basis, average daily 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. Average daily per BOE production for 2006, as compared to 2005, decreased by one percent in the United States, by 37 percent in South Africa and by 26 percent in Tunisia.

During the year ended December 31, 2007, oil and gas volumes delivered under the Company's VPPs decreased by five percent, as compared to 2006.

The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
Oil (Bbls):			
United States	—	2,400	5,280
Argentina	—	2,515	7,869
Canada	267	311	238
Worldwide	267	5,226	13,387
NGLs (Bbls):			
United States	—	—	65
Argentina	—	421	1,824
Canada	371	463	615
Worldwide	371	884	2,504
Gas (Mcf):			
United States	—	36,038	230,171
Argentina	—	43,905	137,032
Canada	44,645	43,434	42,916
Worldwide	44,645	123,377	410,119
Total (BOE):			
United States	—	8,406	43,707
Argentina	—	10,253	32,531
Canada	8,080	8,013	8,005
Worldwide	8,080	26,672	84,243

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 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
Average reported prices:			
Oil (per Bbl):			
United States	$ 63.78	$ 65.73	$ 32.01
South Africa	$ 76.36	$ 65.92	$ 53.01
Tunisia	$ 70.04	$ 63.16	$ 52.98
Worldwide	$ 66.08	$ 65.51	$ 38.61
NGL (per Bbl):			
United States	$ 41.60	$ 35.24	$ 31.72
Gas (per Mcf):			
United States	$ 7.25	$ 6.15	$ 6.94
South Africa	$ 6.76	$ —	$ —
Tunisia	$ 8.77	$ 5.97	$ —
Worldwide	$ 7.26	$ 6.15	$ 6.94
Total (per BOE):			
United States	$ 47.30	$ 42.64	$ 37.09
South Africa	$ 70.98	$ 65.92	$ 53.01
Tunisia	$ 68.33	$ 61.05	$ 52.98
Worldwide	$ 48.99	$ 44.23	$ 38.78
Average realized prices:			
Oil (per Bbl):			
United States	$ 70.26	$ 62.92	$ 54.05
South Africa	$ 76.72	$ 65.74	$ 53.01
Tunisia	$ 70.04	$ 63.16	$ 52.98
Worldwide	$ 70.91	$ 63.42	$ 53.72
NGL (per Bbl):			
United States	$ 41.60	$ 35.24	$ 31.72
Gas (per Mcf):			
United States	$ 6.02	$ 5.96	$ 7.26
South Africa	$ 6.76	$ —	$ —
Tunisia	$ 8.77	$ 5.97	$ —
Worldwide	$ 6.04	$ 5.96	$ 7.26
Total (per BOE):			
United States	$ 44.31	$ 41.37	$ 43.86
South Africa	$ 71.29	$ 65.74	$ 53.01
Tunisia	$ 68.33	$ 61.05	$ 52.98
Worldwide	$ 46.24	$ 43.04	$ 44.84

Hedging 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 2007, 2006 and 2005, the Company's commodity price hedges decreased oil and gas revenues from continuing operations by $83.5 million, $151.2 million and $284.8 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. 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 2007, 2006 and 2005 from the Company's hedging activities, the Company's open and terminated hedge positions at December 31, 2007 and descriptions of the Company's commodity hedge derivatives. Also see

"Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosures about the Company's commodity related derivative financial instruments.

Subsequent to December 31, 2007, the Company entered into additional commodity swap contracts for approximately 69,945 MMBtu per day of the Company's 2008 production at an average price of $7.28 per MMBtu. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning these changes in gas hedge positions.

Deferred revenue. During 2007, 2006 and 2005, the Company's recognition of previously deferred VPP revenue increased oil and gas revenues from continuing operations by $181.2 million, $190.3 million and $75.8 million, respectively. The Company's amortization of deferred VPP revenue is scheduled to increase 2008 oil and gas revenues by $158.1 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 $94.7 million, $48.4 million and $26.5 million during 2007, 2006 and 2005, respectively. The $46.3 million increase during 2007, as compared to 2006, is primarily attributable to (i) $74.9 million of 2007 Alaskan Petroleum Production Tax ("PPT") credit dispositions and (ii) a $4.8 million 2007 royalty obligation accrual adjustment, partially offset by (iii) an $11.3 million decrease in interest income, (iv) a $7.6 million reduction in business interruption insurance claims and (v) a $7.4 million decrease in derivative ineffectiveness income. The $21.9 million increase during 2006, as compared to 2005, is primarily attributable to (i) a $12.9 million increase in interest income primarily attributable to the investing the proceeds from the Argentine and deepwater Gulf of Mexico divestitures during 2006, (ii) $7.4 million of hedge ineffectiveness gains recorded during 2006 and (iii) $5.6 million of Alaskan exploration incentive credits received in 2006, offset by (iv) a $6.6 million decrease in business interruption insurance claims primarily attributable to the 2005 Fain plant fire in the West Panhandle field.

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 and having no current production, the Company has generated PPT related carryforwards. At December 31, 2007, the Company had approximately $90 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.

Gain (loss) on disposition of assets. The Company recorded a net loss on disposition of assets of $2.2 million in 2007, as compared to a net loss of $6.5 million in 2006 and a net gain of $60.1 million during 2005.

In 2005, the gain was primarily related to (i) the sale of the stock of a subsidiary that owned the interest in the Olowi block in Gabon, which resulted in a $47.5 million gain and (ii) a $14 million property insurance settlement on the Company's East Cameron facility that was destroyed by Hurricane Rita, which resulted in a $9.7 million gain.

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. During 2005, the Company recognized gains on the sale of certain assets in Canada and the shelf of the Gulf of Mexico of approximately $166.2 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 2007, 2006 and 2005 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 $420.7 million, $349.1 million and $309.7 million during 2007, 2006 and 2005, 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.

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.

Total production costs per BOE increased during 2006 by 18 percent as compared to 2005 primarily due to (i) the impact of a 126 percent increase in delivered volumes under VPP agreements, for which the Company bears all associated production costs and records no associated sales volumes (representing a per BOE production cost impact of approximately $1.50 during 2006 as compared to $.59 during 2005), (ii) general inflation of field service and supply costs and (iii) increases in production and ad valorem taxes and field utility costs due to increasing commodity and utility prices.

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 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
Lease operating expenses	$ 6.91	$ 5.94	$ 4.95
Third-party transportation charges	0.97	0.79	0.64
Taxes:			
Ad valorem	1.23	1.35	1.17
Production	1.96	1.84	1.73
Workover costs	0.77	0.66	0.48
Total production costs	$ 11.84	$ 10.58	$ 8.97

	Year Ended December 31,		
	2007	**2006**	**2005**
United States	$ 11.79	$ 10.61	$ 8.99
South Africa	$ 22.43	$ 14.47	$ 11.79
Tunisia	$ 5.14	$ 3.41	$ 3.20
Worldwide	$ 11.84	$ 10.58	$ 8.97

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $10.90, $9.52 and $7.76 per BOE for 2007, 2006 and 2005, respectively. Depletion expense, the largest component of DD&A expense, was $10.10, $8.80 and $7.19 per BOE during 2007, 2006 and 2005, respectively. 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 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.

During 2006, 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 proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies, (ii) the sale of proved reserves under VPP agreements, for which the Company removed proved reserves with no corresponding decrease in cost basis, (iii) a $.50 per BOE increase in Tunisian depletion, primarily associated with 2006 and 2005 decreases in the Company's interest in the Adam Concession, offset by (iv) a $3.91 per BOE decrease in South Africa depletion, primarily associated with 2006 and 2005 positive revisions to proved reserves based on well performance.

The following table provides depletion expense per BOE from continuing operations by geographic area for 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
United States	$ 10.27	$ 9.07	$ 7.10
South Africa	$ 12.07	$ 6.28	$ 10.19
Tunisia	$ 5.01	$ 4.25	$ 3.75
Worldwide	$ 10.10	$ 8.80	$ 7.19

Impairment of long-lived 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, 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 the ongoing arbitration among the parties participating in the Block H prospect. Another $10.2 million of the impairment charges relate to the Company's announced intent to dispose of its Nigerian subsidiary that held the interest in Block 320 and the resulting adjustment to reduce its carrying 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.

During 2005, the Company recognized noncash impairment charges of $644 thousand to reduce the carrying value of its Gabonese Olowi field assets as development of the discovery was canceled. See "Critical Accounting Estimates" below and Notes B and S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information pertaining to the Company's accounting policies regarding assessments of impairment and the Equatorial Guinea, Nigeria, Louisiana and Gabonese Olowi field impairments.

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 2007, 2006 and 2005:

	United States	South Africa	Tunisia	Other	Total
	(in thousands)				
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
Year ended December 31, 2005					
Geological and geophysical	$ 63,707	$ 282	$ 1,857	$ 32,214	$ 98,060

Exploratory dry holes	24,462	804	9,041	9,135	43,442
Leasehold abandonments and other	8,957	125	—	3,195	12,277
	$ 97,126	$ 1,211	$ 10,898	$ 44,544	$ 153,779

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 NPRA area and the write-off of the remaining prospect costs in the onshore 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 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.

Significant components of the Company's dry hole expense during 2005 included (i) $21.2 million related to Alaskan well costs, (ii) $9.5 million associated with an unsuccessful Nigerian well, (iii) $3.5 million attributable to an unsuccessful suspended well in the Company's El Hamra permit in Tunisia, (iv) $5.1 million attributable to an unsuccessful suspended well in the Company's Anaguid permit in Tunisia and (v) various other exploratory wells. During 2005, the Company completed and evaluated 180 exploratory/extension wells, 149 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled $129.6 million, $116.6 million and $110.1 million during 2007, 2006 and 2005, respectively. The increase in general and administrative expense during 2007, as compared to 2006, was primarily due to an increase in performance related compensation costs, including the amortization of share-based awards to officers, directors and employees. As of December 31, 2007, the Company has $34.9 million of unrecognized compensation expense related to unvested share-based awards that will be charged to earnings over a weighted average period of approximately one year and five months. The Company continues to monitor its general and administrative expense and is focused on administrative cost control. If Pioneer Southwest completes its initial public offering, the Company expects that its general and administrative expenses would increase.

The increase in general and administrative expense during 2006, as compared to 2005, was primarily due to a full year effect of the 2005 staff increases associated with the Evergreen acquisition.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations from continuing operations was $7.0 million, $3.7 million and $3.3 million for the years ending during 2007, 2006 and 2005, respectively. The increase in accretion of discount on asset retirement obligations during 2007 was primarily due to new wells placed on production from the 2007 drilling program and the carryover of the 2006 drilling program. 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 $135.3 million, $107.1 million and $126.0 million during 2007, 2006 and 2005, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2007 was 6.5 percent, as compared to 6.7 percent and 6.5 percent for the years ended December 31, 2006 and 2005, respectively, including the effects of interest rate derivatives. 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 the completion of the South Africa South Coast Gas project during the third quarter of 2007 and the Alaskan Oooguruk project facilities nearing completion, partially offset by declining interest rates on the Company credit facility.

The decrease in interest expense for 2006 as compared to 2005 was primarily due to the repayment of portions of the Company's outstanding borrowings under the Company's credit facility with proceeds from the divestiture of the deepwater Gulf of Mexico and Argentine assets and an $11.1 million increase in interest capitalized on the Company's Oooguruk and South Coast Gas development projects, partially offset by a $4.1 million decrease in the amortization of interest rate hedge gains.

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 $61.3 million, $32.0 million and $39.8 million during 2007, 2006 and 2005, respectively, associated with the Company's East Cameron platform facility, located on the Gulf of Mexico shelf, that was destroyed during 2005 by Hurricane Rita.

The Company estimates that it will cost approximately $185 million to reclaim and abandon the East Cameron facility. The operations to reclaim and abandon the East Cameron facilities began in January 2007. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis prepared by a third party engineering firm for a majority of the work, an estimate by the Company for the remaining work that was not covered by the third-party analysis and actual abandonment activity to date. The incremental $66.0 million increase in the reclamation and abandonment obligation during 2007 is primarily due to increasing the estimated time that it will take to complete certain aspects of the reclamation and abandonment project based on recent project work experience. During the third quarter of 2007, the Company commenced legal actions against its insurance carriers regarding certain policy coverage issues. However, 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 additional information about the Company's East Cameron facility reclamation and abandonment.

Other expenses. Other expenses were $31.9 million during 2007, as compared to $36.9 million during 2006 and $80.7 million during 2005. The $5.1 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.

The $43.8 million decrease in other expenses during 2006, as compared to 2005, is primarily attributable to (i) a $40.4 million decrease in hedge ineffectiveness charges and (ii) an $18.4 million decrease in loss on early extinguishment of portions of the Company's senior notes, partially offset by (iii) a $4.4 million increase in bad debt expense, (iv) a $4.0 million insurance charge, (v) a $2.7 million increase in non-hedge derivative charges and (vi) $3.4 million of other net increases in other expense components.

Income tax provision. The Company recognized income tax provisions on continuing operations of $112.6 million, $141.0 million and $149.2 million during 2007, 2006 and 2005, respectively. The Company's effective tax rates for 2007, 2006 and 2005 were 32 percent, 48 percent and 45 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 37 percent. The effective tax rates of 2007, 2006 and 2005 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 newly-enacted South African tax law allowing for the deduction of 150 percent of development expenditures, resulting in a $15.7 million tax benefit in 2007;
- an $8.8 million tax benefit in 2007 related to the reversal of Tunisian deferred tax asset valuation allowances previously taken on the Company's Cherouq concession and the recognition of additional tax benefits for costs inherited from the previous owners of the Jenein Nord permit, which management now believes is more likely than not to be realized in the future from forecasted operations;
- 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;
- an $18.9 million U.S. tax provision during 2007 related to the Company no longer having identifiable plans to reinvest South Africa earnings in South Africa;

- recognition of $8.4 million of deferred tax benefit during 2006 as a result of the conversion of senior convertible notes prior to the Company's repayment of the debt principal;
- recognition of $7.2 million of taxes during 2005 associated with the repatriation of foreign earnings pursuant to the American Jobs Creation Act of 2004; 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 2006 and 2007.

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, 2006 and 2005, the Company sold its interests in the following oil and gas asset groups:

Country	**Description of Asset Groups**	**Date Divested**
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005
United States	Two Gulf of Mexico shelf fields	August 2005
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006
Canada	Canadian assets	November 2007

The Company recognized income from discontinued operations of $130.7 million during 2007 as compared to $589.5 million during 2006 and $350.3 million during 2005. Pursuant to SFAS 144, the results of operations of these assets and the related gains on disposition are reported as discontinued operations. See Notes V and W of Notes to Consolidated Financial Statements included in the Financial Statements and Supplementary Data included herein for additional data on discontinued operations.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of contractual obligations and working capital obligations. Funding for exploration, development and acquisition of oil and gas properties and repayment of contractual obligations may be provided by any combination of internally-generated cash flow, proceeds from the disposition of nonstrategic assets or alternative financing sources as discussed in "Capital resources" and "Financing activities" below. Generally, funding for the Company's working capital obligations is provided by internally-generated cash flows.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2007, 2006 and 2005 totaled $2.1 billion, $1.4 billion and $1.1 billion, respectively. 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's 2005 expenditures for additions to oil and gas properties were internally funded by $1.3 billion of net cash provided by operating activities.

The Company strives to maintain its indebtedness at levels which will provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2008 is approximately $1.0 billion. The Company currently expects that cash flows from operations will be sufficient to fund the 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, 2007, 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, 2007:

	Payments Due by Year			
	2008	**2009 and 2010**	**2011 and 2012**	**Thereafter**
	(in thousands)			
Long-term debt (a)	$ 3,777	$ —	$ 1,119,110	$ 1,726,875
Operating leases (b)	28,913	26,126	22,496	75,907
Drilling commitments (c)	190,155	179,570	8,065	—
Derivative obligations (d)	228,577	77,245	—	—
Other liabilities (e)	140,206	37,334	8,188	146,329
Transportation commitments (f)	26,086	50,607	36,103	31,967
VPP obligations (g)	158,138	238,121	87,021	—
	$ 775,852	$ 609,003	$ 1,280,983	$ 1,981,078

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(a) See 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, 2007.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2007. These liabilities include $69.9 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. The Company expects that these resources will be sufficient to fund its capital commitments for the foreseeable future. For 2007, the Company's capital commitments exceeded estimated cash flows from operations, resulting in additional borrowings under the Company's credit facility. For 2008, the Company currently expects that cash flow from operations will be sufficient to fund the Company's $1.0 billion capital budget.

Asset divestitures. In November 2007, the Company sold all of the common stock of its Canadian subsidiaries for net proceeds of $525.7 million. The proceeds from the sale were utilized to reduce amounts outstanding under the Company's credit facility. Associated therewith, the Company reported a gain of $101.3

million during the fourth quarter of 2007. The results of operations for the Canadian assets are included in the Company's discontinued operations.

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.

During May 2005, the Company sold all of its interests in the Martin Creek, Conroy Black and Lookout Butte oil and gas properties in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During August 2005, the Company sold all of its interests in certain oil and gas properties on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 million. During October 2005, the Company sold all of its shares in a subsidiary that owns the interest in the Olowi block in Gabon for net proceeds of $47.9 million, resulting in a gain of $47.5 million. The net cash proceeds from the 2005 divestitures were used to reduce outstanding indebtedness.

During 2005, the Company sold 27.8 MMBOE of proved reserves, by means of three VPPs for net proceeds of $892.6 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were used to reduce outstanding indebtedness.

See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's VPPs.

Operating activities. Net cash provided by operating activities during 2007, 2006 and 2005 was $775.3 million, $754.8 million and $1.3 billion, respectively. 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 disposal of Alaskan PPT credits, offset by the cash provided by operating activities associated with the 2006 deepwater Gulf of Mexico and Argentine asset dispositions and the 2007 disposal of the Canadian assets. The decrease in net cash provided by operating activities in 2006, as compared to that of 2005, was primarily due to the loss of cash flow from the aforementioned asset divestitures.

Investing activities. Net cash used in investing activities during 2007 was $1.8 billion, as compared to net cash provided by investing activities of $145.5 million and $84.7 million during 2006 and 2005, respectively. 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. The increase in net cash provided by investing activities during 2006, as compared to 2005, was primarily due to a $396.2 million increase in proceeds from disposition of assets, partially offset by a $280.6 million increase in additions to oil and gas properties. 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 2007 was $1.0 billion, as compared to net cash used in financing activities of $913.5 million and $1.4 billion during 2006 and 2005, respectively. 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. During 2005, financing activities were comprised of $353.6 million of net principal repayments on long-term debt, $60.1 million of payments of other noncurrent liabilities, primarily comprised of cash settlements of acquired hedge obligations, $30.3 million of dividends paid and $949.3 million of stock repurchases, partially offset by $41.6 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases.

During September 2005, the Company announced that the board of directors had approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock. During 2006 and 2005, the Company expended a total of $348.9 million to acquire 8.9 million shares of stock and $949.3 million to acquire 20.0 million shares of stock, respectively, of which $345.3 million and $640.7 million, respectively, were repurchased pursuant to the $1 billion repurchase program. In 2007, the Board authorized share repurchases of up to $750 million of the Company's common stock. Through December 31, 2007, the Company had repurchased $212.8 million of common stock under this 2007 authorized program.

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. On August 15, 2007, $32.1 million principal amount of the Company's 8.25% senior notes matured and were also 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. 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 terminate during February 2010 and $200 million during February 2011.

During March 2007, the Company issued $500 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 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 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.

During April 2005, $131.0 million of the Company's 8 7/8% senior notes due 2005 matured and were repaid. During 2005, the Company also redeemed the remaining $64.0 million and $16.2 million, respectively, of aggregate principal amount of its 9 5/8% senior notes due 2010 and its 7.50% senior notes due 2012. During September 2005, the Company accepted tenders to purchase $188.4 million in principal amount of the 5.875% senior notes due 2012 for $199.9 million. The Company utilized unused borrowing capacity under its credit facility to fund these financing activities.

During 2007, the Company's board of directors declared total dividends of $.27 per common share. Associated therewith, the Company paid $16.0 million of aggregate dividends during April 2007 and $16.8 million of aggregate dividends during October 2007. Future dividends are at the discretion of the Board, and, if declared, the Board may change the current dividend amount, including in response to the Company's liquidity and capital resources at the time.

In 2007, Pioneer Southwest filed a preliminary registration statement (subject to completion) with the SEC to sell limited partner interests. If the offering is completed, Pioneer Southwest would own interests in certain oil and gas properties currently owned by the Company in the Spraberry field in the Permian Basin of West Texas. Pioneer Southwest's registration statement contemplates an offering of 35.3 percent (before underwriters' over-allotment option) of its limited partner interests to the public (the "Offering"). The Offering has been postponed due to market conditions and timing of the Offering remains uncertain. Completion of the Offering is subject to market conditions and numerous other risks beyond the control of Pioneer Southwest, and therefore it is possible that the Offering will not be completed, will not raise the planned amount of capital even if the Offering is completed, or will not be completed when planned.

In October 2007, Pioneer Southwest entered into a $300 million unsecured revolving credit facility ("PSE Credit Agreement") with a syndicate of banks. The PSE Credit Agreement would mature five years following the closing of the Offering and would contain certain financial covenants that would be applicable to Pioneer Southwest. As a result of the most restrictive covenant, borrowings under the PSE Credit Agreement would be expected to be initially limited to approximately $150 million. It is a condition to the obligations of the lenders under the PSE Credit Agreement that Pioneer Southwest completes the Offering. Pioneer Southwest is seeking an extension of the facility from the lenders. There can be no assurance that the lenders will agree to an extension, or if they do agree, that the terms of the facility will remain unchanged. If Pioneer Southwest were to seek a replacement facility, there can be no assurance that it would be able to do so or if it were successful, that the terms would be as favorable to Pioneer Southwest as the terms under the PSE Credit Agreement. See Notes F and W of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the Pioneer Southwest credit facility and initial public offering.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company 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 $1.1 billion of outstanding borrowings under the credit facility as of December 31, 2007. Including $80 million of undrawn and outstanding letters of credit under the credit facility, the Company had $307 million of unused borrowing capacity as of December 31, 2007.

In January 2008, the Company issued $500 million of 2.875% senior convertible notes ("2.875% Convertible Notes"). The notes will be convertible under certain circumstances using a net share settlement process into a combination of cash and Pioneer common stock pursuant to a formula. The Company used the net proceeds from the 2.875% Convertible Notes to reduce indebtedness under its credit facility.

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 2005 and 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 and $(6.6) million, respectively. However, during 2007 the CND strengthened significantly against the USD, associated with which 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. ("Moodys"), which are subject to regular reviews. S&P's rating for the Company is BB+ with a stable outlook. Moodys rating for the Company is Ba1 with a negative outlook. S&P and Moodys 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, 2007, the Company was in compliance with all of its debt covenants.

Book capitalization and current ratio. The Company's book capitalization at December 31, 2007 was $5.8 billion, consisting of debt of $2.8 billion and stockholders' equity of $3.0 billion. The Company's debt to book capitalization increased to 48 percent at December 31, 2007 from 33 percent at December 31, 2006, primarily due to increased indebtedness which was used to fund the Company's additions to oil and gas properties and stock repurchases. The Company's debt to book capitalization at December 31, 2005 was 48 percent and decreased to 33 percent at December 31, 2006. The decrease was principally due to the reduction of debt from the application of the proceeds received from the divestiture of the deepwater Gulf of Mexico assets and Argentine assets in 2006. The Company's ratio of current assets to current liabilities was .77 to 1.00 at December 31, 2007, as compared to .60 to 1.00 at December 31, 2006.

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. 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 2007, 2006 and 2005, the Company recognized exploration, abandonment, geological and geophysical expense from (i) continuing operations of $279.3 million, $250.2 million and $153.8 million, respectively, and (ii) discontinued operations of $14.4 million, $21.3 million and $73.4 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, 2007, 2006 and 2005 were 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, 2007 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 its outlook of future commodity prices and net cash flows that may be generated by the properties and if a significant downward revision has occurred to the estimated proved reserves. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated.

Impairment of unproved oil and gas properties. At December 31, 2007, the Company carried unproved property costs of $277.5 million. Management periodically assesses unproved oil and gas properties for impairment, on a project-by-project basis. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects impacts the amount and timing of impairment provisions, if any.

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 generally does not carry the costs of drilling an exploratory well as an asset in its Consolidated Balance Sheets for more than one year following the completion of drilling unless the exploratory well finds oil and gas reserves in an area requiring a major capital expenditure and 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, 2007, 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 the estimation of proved reserves as described above. See Note B 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 subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. Under GAAP, a liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. See Note 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. The Company adopted the "modified prospective" approach as prescribed under SFAS No. 123(R) on January 1, 2006. Under this approach, the Company is required to expense all options and other stock-based compensation that vested during the year of adoption based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the inputs necessary for using the various valuation methods utilized by the Company. 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 2007:

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. SFAS 157 is effective for fiscal years beginning after November 15, 2007. The implementation of SFAS 157 will not have a material impact 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. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The implementation of SFAS 159 is not expected to 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"). 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 acquiree at the acquisition date, measured at the fair value as of that date. This includes the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting for pre-acquisition gain and loss contingencies, the recognition of capitalized in-process research and development, the

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accounting for acquisition-related restructuring cost accruals, the treatment of acquisition related transaction costs and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. 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. The implementation of SFAS 141(R) is not expected to have a material effect on the financial condition or results of operations of the Company.

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, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the non-controlling interest. SFAS 160 is effective for the Company on January 1, 2009 and is not expected to have a significant impact on the Company's financial statements.

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, 2007 and 2006, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices. Although certain derivative contracts to which the Company has been a party did not qualify as hedges, the Company does not enter into derivative or other financial instruments for trading purposes.

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 2007. During 2007, 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 2007:

	Derivative Contract Net Liabilities (a)			
	Commodities	**Interest Rate**	**Foreign Exchange Rate**	**Total**
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2006	$ (68,228)	$ —	$ —	$ (68,228)
Changes in contract fair values (b)	(160,839)	(1,537)	(1,500)	(163,876)
Contract maturities	(70,772)	—	(61)	(70,833)
Contract terminations	65,429	1,537	61	67,027
Fair value of contracts outstanding as of December 31, 2007	$ (234,410)	$ —	$ (1,500)	$ (235,910)

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(a) Represents the fair values of open derivative contracts subject to market risk. The Company also had $69.9 million and $131.1 million of obligations under terminated derivatives as of December 31, 2007 and 2006, respectively, for which no market risk exists.
(b) At inception, new derivative contracts entered into by the Company have no intrinsic value.

Quantitative Disclosures

Foreign exchange rate sensitivity. Prior to its sale, the Company's Canadian subsidiary entered into short-term forward currency agreements to purchase Canadian dollars with U.S. dollar gas sales proceeds. The Company did not designate these derivatives as hedges due to their short-term nature.

During November 2007, the Company invested $131.7 million Canadian dollars ("CND") in a CND-denominated escrow account associated with the sale of the Company's Canadian assets (see Notes V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding 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 U.S. dollars ("USD") to be delivered during May 2008. As of December 31, 2007, the fair value of the foreign exchange rate swap contracts was a liability of $1.5 million. 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. 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, 2007 and 2006 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, 2007 and 2006. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 8, 2008. As of December 31, 2007, the Company was not a party to material derivatives that would subject it to interest rate sensitivity.

Interest Rate Sensitivity

Debt Obligations as of December 31, 2007

	Year Ending December 31,							**Liability Fair Value December 31,**
	2008	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**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 (b)	$ —	$ —	$ —	$ —	$ 1,113,000	$ —	$ 1,113,000	$ 1,113,000
Weighted average interest rate	3.51 %	3.91 %	4.78 %	5.38 %	5.48 %	— %		

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(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, 2006

Year Ending December 31,							**Liability Fair Value December 31,**
2007	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**	**2006**
(dollars in thousands)							

Total Debt:								
Fixed rate principal maturities (a)	$ 32,075	$ 3,777	$ —	$ —	$ —	$ 1,232,985	$ 1,268,837	$ 1,244,846
Weighted average interest rate	6.64 %	6.25 %	6.51 %	6.51 %	6.51 %	6.51 %		
Variable rate principal maturities	$ —	$ —	$ —	$ 22,960	$ 305,040	$ —	$ 328,000	$ 328,000
Weighted average interest rate (b)	6.23 %	5.87 %	5.88 %	5.96 %	6.28 %	— %		

(a) Represents maturities of principal amounts excluding (i) debt issuance discounts and premiums and (ii) deferred fair value hedge gains and losses.
(b) Represents the average rates being paid on debt projected forward proportionate to the forward yield curve for LIBOR on February 19, 2007.

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, 2007 and 2006. As of December 31, 2007 and 2006, substantially all of the Company's oil, NGL and gas derivative financial instruments qualified as hedges.

Commodity hedge instruments. The Company hedges 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 hedge 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, 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 (a):				
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 (b)	$ 97.22	$ 92.62	$ 90.88	

(a) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices by calendar quarter.
(b) The average forward NYMEX oil prices are based on February 15, 2008 market quotes.

Oil Price Sensitivity

Derivative Financial Instruments as of December 31, 2006

	Year Ending December 31, 2007	2008	2009	Liability Fair Value at December 31, 2006 (in thousands)

Oil Hedge Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	4,512	6,500	—	$ 130,574
Weighted average fixed price per Bbl	$ 31.44	$ 31.19	$ —	
Average forward NYMEX oil prices (a)	$ 61.47	$ 63.93	$ 63.86	

(a) The average forward NYMEX oil prices are based on February 1, 2007 market quotes.

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, 2007

	Year Ending December 31,			Asset Fair Value at December 31,
	2008	2009	2010	2007 (in thousands)
Gas Hedge Derivatives (a):				
Average daily notional MMBtu volumes (b):				
Swap contracts (c)	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 (d)	$ 9.18	$ 9.36	$ 9.17	

(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 hedge volumes and weighted average prices by calendar quarter.

(c) Subsequent to December 31, 2007 and through February 15, 2008, the Company entered into additional swap contracts for approximately 69,945 MMBtu per day of the Company's 2008 production at an average price of $7.28 per MMBtu.

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

Gas Price Sensitivity

Derivative Financial Instruments as of December 31, 2006

	Year Ending December 31,		Asset Fair Value at December 31,
	2007	2008	2006
			(in thousands)
Gas Hedge Derivatives (a):			
Average daily notional MMBtu volumes:			
Swap contracts	86,194	15,000	$ 54,835
Weighted average fixed price per MMbtu	$ 8.13	$ 8.62	
Collar contracts	6,164	—	$ 7,511
Weighted average ceiling price per MMbtu	$ 11.52	$ —	
Weighted average floor price per MMbtu	$ 9.00	$ —	
Average forward NYMEX gas prices (b)	$ 7.99	$ 8.29	

(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) The average forward NYMEX gas prices are based on February 19, 2007 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 hedge 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 hedge 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 11 percent of the Company's 2007 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. The Company also has an exploration permit in Equatorial Guinea. 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, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, 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 No. 109," effective January 1, 2007. As discussed in Note B to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment," effective January 1, 2006. 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), the Company's internal control over financial reporting as of December 31, 2007, 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 19, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas

February 19, 2008

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2007	2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12,171	$ 7,033
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $7,657 and $6,999 as of December 31, 2007 and 2006, respectively	283,249	195,534
Due from affiliates	583	3,837
Income taxes receivable	40,046	24,693
Inventories	97,619	95,131
Prepaid expenses	9,378	11,509
Deferred income taxes	108,073	82,927
Other current assets:		
Derivatives	33,970	63,665
Other	179,966	52,229
Total current assets	765,055	536,558
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	8,973,634	7,967,708
Unproved properties	277,479	210,344
Accumulated depletion, depreciation and amortization	(2,028,472)	(1,895,408)
Total property, plant and equipment	7,222,641	6,282,644
Deferred income taxes	10,263	345
Goodwill	310,870	309,908
Other property and equipment, net	152,990	131,840
Other assets:		
Derivatives	684	4,333
Other, net of allowance for doubtful accounts of $4,573 and $4,045 as of December 31, 2007 and 2006, respectively	154,478	89,771
	$ 8,616,981	$ 7,355,399

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, 2007	2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 350,782	$ 332,795
Due to affiliates	27,634	17,025
Interest payable	42,020	31,008
Income taxes payable	12,842	12,865
Other current liabilities:		
Derivatives	262,547	141,898
Deferred revenue	158,138	181,232
Other	140,206	170,156
Total current liabilities	994,169	886,979
Long-term debt	2,755,491	1,497,162
Derivatives	77,929	125,459
Deferred income taxes	1,229,677	1,172,507
Deferred revenue	325,142	483,279
Other liabilities and minority interests	191,851	205,342
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 123,389,014 and 122,686,073 shares issued at December 31, 2007 and 2006, respectively	1,234	1,227
Additional paid-in capital	2,693,257	2,654,047
Treasury stock, at cost: 5,661,692 and 1,183,090 shares at December 31, 2007 and 2006, respectively	(245,601)	(53,274)
Retained earnings	822,089	497,488
Accumulated other comprehensive income (loss):		
Net deferred hedge losses, net of tax	(228,257)	(167,220)
Cumulative translation adjustment	—	52,403
Total stockholders' equity	3,042,722	2,984,671
Commitments and contingencies		
	$ 8,616,981	$ 7,355,399

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)

	Year Ended December 31,		
	2007	**2006**	**2005**
Revenues and other income:			
Oil and gas	$ 1,740,851	$ 1,458,940	$ 1,338,883
Interest and other	94,661	48,390	26,460
Gain (loss) on disposition of assets, net	(2,163)	(6,459)	60,063
	1,833,349	1,500,871	1,425,406
Costs and expenses:			
Oil and gas production	420,738	349,066	309,714
Depletion, depreciation and amortization	387,397	314,081	267,757
Impairment of long-lived assets	26,215	—	644
Exploration and abandonments	279,329	250,196	153,779
General and administrative	129,587	116,595	110,104
Accretion of discount on asset retirement obligations	7,028	3,726	3,349
Interest	135,270	107,050	125,987
Hurricane activity, net	61,309	32,000	39,813
Other	31,852	36,919	80,723
	1,478,725	1,209,633	1,091,870
Income from continuing operations before income taxes	354,624	291,238	333,536
Income tax provision	(112,645)	(141,021)	(149,231)
Income from continuing operations	241,979	150,217	184,305
Income from discontinued operations, net of tax	130,749	589,514	350,263
Net income	$ 372,728	$ 739,731	$ 534,568
Basic earnings per share:			
Income from continuing operations	$ 2.01	$ 1.21	$ 1.35
Income from discontinued operations, net of tax	1.09	4.74	2.55
Net income	$ 3.10	$ 5.95	$ 3.90
Diluted earnings per share:			
Income from continuing operations	$ 1.99	$ 1.19	$ 1.32
Income from discontinued operations, net of tax	1.07	4.62	2.48
Net income	$ 3.06	$ 5.81	$ 3.80
Weighted average shares outstanding:			
Basic	120,158	124,359	137,110
Diluted	121,659	127,608	141,417

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	Deferred Compensation	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Losses, Net of Tax	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Balance as of December 31, 2004	143,625	$ 1,438	$ 3,705,304	$ (27,793)	$ (22,558)	$ (634,146)	$ (241,350)	$ 50,885	$ 2,831,780
Dividends declared ($.22 per common share)	—	—	—	—	—	(30,339)	—	—	(30,339)
Exercise of long-term incentive plan stock options and employee stock purchases	2,429	—	1,310	94,670	—	(54,403)	—	—	41,577
Purchase of treasury stock	(19,984)	—	—	(949,259)	—	—	—	—	(949,259)
Tax benefits related to stock-based compensation	—	—	18,752	—	—	—	—	—	18,752
Deferred compensation:									
Compensation deferred	762	14	56,146	—	(56,160)	—	—	—	—
Deferred compensation included in net income	—	—	—	—	26,857	—	—	—	26,857
Forfeiture of deferred compensation	—	—	(5,700)	—	6,034	—	—	—	334
Net income	—	—	—	—	—	534,568	—	—	534,568
Other comprehensive income (loss):									
Deferred hedging activity, net of tax:									
Net deferred hedge losses	—	—	—	—	—	—	(539,384)	—	(539,384)
Net hedge losses included in continuing operations	—	—	—	—	—	—	180,941	—	180,941
Net hedge losses included in discontinued operations	—	—	—	—	—	—	93,157	—	93,157
Deferred translation adjustment gain	—	—	—	—	—	—	—	8,118	8,118
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:									
Adopted 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

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	Deferred Compensation	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Losses, Net of Tax	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Dividends declared ($0.27 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 included in 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 CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2007	2006	2005
Cash flows from operating activities:			
Net income	$ 372,728	$ 739,731	$ 534,568
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	387,397	314,081	267,757
Impairment of long-lived assets	26,215	—	644
Exploration expenses, including dry holes	171,751	140,135	49,037
Hurricane activity	66,000	75,000	39,813
Deferred income taxes	123,819	161,761	99,379
(Gain) loss on disposition of assets, net	2,163	6,459	(60,063)
Loss on extinguishment of debt	—	8,076	25,975
Accretion of discount on asset retirement obligations	7,028	3,726	3,349
Discontinued operations	(76,423)	(489,959)	423,728
Interest expense	17,049	11,042	4,399
Commodity hedge related activity	12,084	(8,443)	18,181
Amortization of stock-based compensation	35,309	32,065	26,857
Amortization of deferred revenue	(181,231)	(190,327)	(75,773)
Other noncash items	3,182	14,486	19,563
Change in operating assets and liabilities, net of effects from acquisitions and dispositions:			
Accounts receivable, net	(96,691)	121,360	(128,015)
Income taxes receivable	(15,378)	(23,495)	(1,198)
Inventories	(10,901)	(48,060)	(36,948)
Prepaid expenses	656	4,808	(7,504)
Other current assets, net	(2,946)	(42,484)	972
Accounts payable	30,122	(36,085)	83,960
Interest payable	11,012	(6,500)	(7,115)
Income taxes payable	(23)	(3,695)	8,950
Other current liabilities	(107,607)	(28,854)	(13,362)
Net cash provided by operating activities	775,315	754,828	1,277,154
Cash flows from investing activities:			
Payments for acquisition, net of cash acquired	—	—	(965)
Proceeds from disposition of assets, net of cash sold	420,874	1,644,829	1,248,581
Additions to oil and gas properties	(2,067,648)	(1,403,879)	(1,123,297)
Additions to other assets and other property and equipment, net	(136,218)	(95,435)	(39,585)
Net cash provided by (used in) investing activities	(1,782,992)	145,515	84,734
Cash flows from financing activities:			
Borrowings under long-term debt	2,030,000	1,426,490	1,203,190
Principal payments on long-term debt	(778,630)	(1,981,164)	(1,556,763)

Borrowings (payments) of other liabilities	768	610	(60,129)
Exercise of long-term incentive plan stock options and employee stock purchase plan	13,891	17,381	41,577
Purchase of treasury stock	(221,424)	(348,945)	(949,259)
Excess tax benefits from share-based payment arrangements	3,828	5,989	—
Payment of financing fees	(4,310)	(2,178)	(1,911)
Dividends paid	(32,804)	(31,726)	(30,339)
Net cash provided by (used in) financing activities	1,011,319	(913,543)	(1,353,634)
Net increase (decrease) in cash and cash equivalents	3,642	(13,200)	8,254
Effect of exchange rate changes on cash and cash equivalents	1,496	1,431	3,291
Cash and cash equivalents, beginning of year	7,033	18,802	7,257
Cash and cash equivalents, end of year	$ 12,171	$ 7,033	$ 18,802

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,		
	2007	2006	2005
Net income	$ 372,728	$ 739,731	$ 534,568
Other comprehensive income (loss):			
Net hedge activity, net of tax:			
Net deferred hedge gains (losses)	(94,330)	118,139	(539,384)
Net hedge losses included in continuing operations	52,686	96,530	180,941
Net hedge (gains) losses included in discontinued operations	(19,393)	124,747	93,157
Translation adjustment:			
Deferred translation adjustment gain (loss)	77,744	(6,600)	8,118
Net gain included in discontinued operations	(130,147)	—	—
Other comprehensive income (loss)	(113,440)	332,816	(257,168)
Comprehensive income	$ 259,288	$ 1,072,547	$ 277,400

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

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2007, 2006 and 2005

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. 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, that was disposed of in 2007. Associated therewith, the Company has recognized minority interests in consolidated subsidiaries of $11.9 million and $14.4 million in other liabilities and minority interests in the accompanying Consolidated Balance Sheets as of December 31, 2007 and 2006, respectively.

Minority interests in the net losses of the Company's consolidated Nigerian subsidiary totaled $2.8 million, $4.9 million and $5.2 million for the years ended December 31, 2007, 2006 and 2005, respectively, and are included in interest and other income in the accompanying Consolidated Statements of Operations. Minority interests in the net income of the Company's consolidated United States subsidiaries totaled $2.4 million, $2.6 million and $3.5 million for the years ended December 31, 2007, 2006 and 2005, respectively, and are included in other expense in the accompanying Consolidated Statements of Operations.

Discontinued operations. During 2007, 2006 and 2005, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005
United States	Two Gulf of Mexico shelf fields	August 2005
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006
Canada	Canadian assets	November 2007

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 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

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revenues and expenses during the reporting periods. Depletion of oil and gas properties and impairment of goodwill and oil and gas properties, in part, is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved 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.

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.

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, 2007 or 2006.

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, 2007 or 2006.

Inventories. Inventories were comprised of $94.3 million and $93.7 million of materials and supplies and $3.3 million and $1.4 million of commodities as of December 31, 2007 and 2006, 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. Commodities inventory is carried at the lower of average cost or market, on a first-in, first-out basis. Any impairments of inventory are reflected in gain (loss) on disposition of assets in the Consolidated Statements of Operations. As of December 31, 2007 and 2006, the Company's materials and supplies inventory was net of $1.1 million and $4.2 million, respectively, of valuation reserve 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.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its Consolidated Balance Sheets for more than one year following the completion of drilling unless the exploratory well finds oil and gas reserves in an area requiring a major capital expenditure and 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

PIONEER NATURAL RESOURCES COMPANY

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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 ten treating facilities. The Company operates two of the gas processing plants and all ten 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 from continuing operations generated from the plant and treating facilities for the three years ended December 31, 2007, 2006 and 2005 were $40.0 million, $37.8 million and $38.0 million, respectively. Third party expenses from continuing operations attributable to the plants and treating facilities for the same respective periods were $12.1 million, $8.4 million and $7.8 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.

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 United States Raton Basin and Barnett Shale play for $352.2 million for the purpose of conducting oil and gas producing activities. 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 Energy Partners L.P. ("Pioneer Southwest"), a subsidiary of the Company. See Note W for additional information on the Pioneer Southwest initial public offering. The Company controls 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, provides 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 with PNR USA. Under the terms of the Holdings Credit Agreement and

PIONEER NATURAL RESOURCES COMPANY

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Management Agreement, PNR Holdings LLC is a VIE in which PNR USA will receive substantially all of the entity's expected residual returns and absorb substantially all of the entity's expected losses. PNR USA's loans under the Holdings Credit Agreement are secured by the property interests acquired by PNR Holdings LLC. General creditors of PNR Holdings LLC may lack 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 having a net carrying value of $260.3 million and unproved oil and gas properties with a carrying value of $91.5 million are included in the Consolidated Balance Sheet of the Company. Outstanding PNR Holdings LLC borrowings of $351.8 million under the Holdings Credit Agreement have been eliminated in consolidation against the associated loans from PNR USA.

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 $16.9 million since September 28, 2004 for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the Evergreen merger. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", 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 2007, the Company performed its annual assessment of impairment of the goodwill and determined that there was no impairment.

Other property, plant and equipment, net. Other property, plant and equipment is stated at cost and primarily consists of items such as heavy equipment and 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, 2007 and 2006, other property, plant and equipment was net of accumulated depreciation of $166.6 million and $145.3 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 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

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accumulated other comprehensive income (loss) - net deferred hedge 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.

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. During 2006, the Company retired 22.9 million treasury shares, resulting in a reduction in treasury stock of $1.0 billion.

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, natural gas liquid ("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, NGL entitlement assets or NGL entitlement liabilities as of December 31, 2007 or 2006. The following table presents the Company's oil entitlement liabilities and gas entitlement assets and liabilities with their associated volumes as of December 31, 2007 and 2006:

	December 31,			
	2007		2006	
	Amount	Volume	Amount	Volume

	(dollars in millions)			
Oil entitlement liabilities (volumes in MBbls)	$ 12.6	129	$ —	—
Gas entitlement assets (volumes in MMcf)	$ 8.8	3,291	$ 13.0	4,201
Gas entitlement liabilities (volumes in MMcf)	$ 4.3	1,127	$ 3.9	1,082

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. Among other items, SFAS 123(R) eliminates the use of the Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), intrinsic value method of accounting and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in the financial statements. The Company elected to use the modified prospective method for adoption of SFAS 123(R), which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested stock options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value on the date of grant, was recognized in the Company's financial statements over their remaining vesting periods, which ended in August 2006. 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

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and (c) the Monte Carlo simulation method for the fair value of performance unit awards. Prior to the adoption of SFAS 123(R), the Company followed the intrinsic value method in accordance with APB 25 to account for stock options. Prior period financial statements have not been restated. The modified prospective method requires the Company to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to its prior policy of recognizing forfeitures as they occurred. The Company recorded no cumulative effect as a result of adopting SFAS 123(R).

Additionally, under the provisions of SFAS 123(R), deferred compensation recorded under APB 25 related to equity-based awards should 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, 2007 and 2006, the Company recorded $35.3 million and $32.1 million of compensation costs for all stock-based plans, respectively, including compensation costs of $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, 2007 and 2006, do not include 1,960,475 shares and 1,946,211 shares, respectively, related to unvested restricted stock awards.

The following table illustrates the pro forma effect on net income and net income per share as if the Company had applied the fair value recognition provisions of SFAS No. 123(R) to stock-based compensation during the year ended December 31, 2005:

	Year Ended December 31, 2005 (in thousands, except per share amounts)
Net income, as reported	$ 534,568
Plus: Stock-based compensation expense included in net income for all awards, net of tax (a)	17,054
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of tax (a)	(19,772)
Pro forma net income	$ 531,850

Net income per share:	
Basic - as reported	$ 3.90
Basic - pro forma	$ 3.88
Diluted - as reported	$ 3.80
Diluted - pro forma	$ 3.78

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(a) For the year ended December 31, 2005, stock-based compensation expense included in net income is net of tax benefits of $9.8 million. Similarly, stock-based compensation expense determined under the fair value based method for the year ended December 31, 2005 is net of tax benefits of $11.4 million. See Note P for additional information regarding the Company's income taxes.

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

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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 the 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 non-U.S. 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").

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 and, at December 31, 2007, the Company did not translate a Canadian balance sheet into U.S dollars.

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 as of December 31, 2006 and 2005 and for the years ended December 31, 2007, 2006 and 2005:

	December 31,		
	2007	**2006**	**2005**
U.S. Dollar from Canadian Dollar - Balance Sheet		.8577	.8606
U.S. Dollar from Canadian Dollar - Statement of Operations	.9365	.8817	.8279

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

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. SFAS 157 is effective for fiscal years beginning after November 15, 2007. The implementation of SFAS 157 will not have a material impact 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. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The implementation of SFAS 159 is not expected to 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"). 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 acquiree at the acquisition date, measured at the fair value as of that date. This includes the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting for pre-acquisition gain and loss contingencies, the recognition of capitalized in-process research and development, the accounting for acquisition-related restructuring cost accruals, the treatment of acquisition related transaction costs and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. 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. The

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implementation of SFAS 141(R) is not expected to have a material effect on the financial condition or results of operations of the Company.

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, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS 160 is effective for the Company on January 1, 2009 and is not expected to have a significant impact on the Company's financial statements.

NOTE C. Proved Property Acquisitions

During the years ended December 31, 2007, 2006 and 2005, the Company expended approximately $331.6 million, $78.3 million and $173.4 million, respectively, to acquire working interests in proved oil and gas properties. During 2007, the Company's proved oil and gas property acquisitions primarily comprised property interests in the Permian Basin, the Raton Basin, the Barnett Shale play and onshore Gulf Coast. During 2006, the Company's proved oil and gas property acquisitions primarily comprised property interests in the Permian Basin, onshore Gulf Coast and Alaska. During 2005, the Company's proved oil and gas property acquisitions primarily comprised property interests in the Permian Basin and onshore Gulf Coast.

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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in thousands)		

Beginning capitalized exploratory well costs	$ 265,053	$ 198,291	$ 126,472
Additions to exploratory well costs pending the determination of proved reserves	434,321	451,109	243,272
Reclassification due to determination of proved reserves	(388,630)	(193,480)	(78,334)
Disposition of wells sold	(20,369)	(52,628)	—
Exploratory well costs charged to expense (a)	(159,745)	(138,239)	(93,119)
Ending capitalized exploratory well costs	$ 130,630	$ 265,053	$ 198,291

(a) Includes exploratory well costs of discontinued operations of $4.4 million, $11.1 million and $46.4 million in 2007, 2006 and 2005, respectively.

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The following table provides an aging as of December 31, 2007, 2006 and 2005 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,		
	2007	2006	2005
	(in thousands, except project counts)		
Capitalized exploratory well costs that have been suspended:			
One year or less	$ 76,237	$ 126,749	$ 84,042
More than one year	54,393	138,304	114,249
	$ 130,630	$ 265,053	$ 198,291
Number of projects with exploratory well costs that have been suspended for a period greater than one year	8	14	14

The following table provides the capitalized costs of exploration projects that have been suspended for more than one year as of December 31, 2007:

	Year Costs Incurred			
	Total	2007	2006	2005
	(in thousands)			
United States:				
Lay Creek	$ 41,503	$ 10,243	$ 31,260	$ —
Other	8,960	1,639	5,912	1,409
International	3,930	(15)	3,945	—
Total	$ 54,393	$ 11,867	$ 41,117	$ 1,409

The following discussion describes the history and status of each significant suspended exploratory project as of December 31, 2007:

Lay Creek. The Company's Lay Creek project is a coal bed methane pilot program located in northwestern

Colorado. The Company has drilled 18 wells in six separate pilot areas and completed workovers and recompletions on 14 wells drilled by a previous operator. The Company completed the water treatment facilities and initiated sales of production in 2007. Determination of success of the pilot project is dependent on the ability to dewater the formation and determine if commercial quantities of gas can be produced. The pilot project is currently in the dewatering phase and a determination of commerciality should be known by the end of 2008.

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NOTE E. Disclosures About Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2007 and 2006:

	December 31, 2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Net derivative contract liabilities:				
Commodity price hedges	$ (234,410)	$ (234,410)	$ (68,228)	$ (68,228)
Terminated commodity price hedges	$ (69,912)	$ (69,912)	$ (131,131)	$ (131,131)
Foreign exchange rate swaps	$ (1,500)	$ (1,500)	$ —	$ —
Financial assets:				
Trading securities	$ 23,396	$ 23,396	$ 18,582	$ 18,582
Notes receivable due 2008 to 2011	$ 16,680	$ 16,680	$ 23,607	$ 23,607
Canadian escrow deposit account	$ 132,025	$ 132,025	$ —	$ —
Financial liabilities – long-term debt:				
Credit facility	$ (1,113,000)	$ (1,113,000)	$ (328,000)	$ (328,000)
8.25% senior notes due 2007	$ —	$ —	$ (32,081)	$ (32,511)
6.50% senior notes due 2008	$ (3,776)	$ (3,776)	$ (3,761)	$ (3,798)
5.875% senior notes due 2012	$ (6,213)	$ (5,968)	$ (6,235)	$ (5,903)
5.875% senior notes due 2016	$ (434,442)	$ (458,961)	$ (427,588)	$ (497,054)
6.65% senior notes due 2017	$ (498,534)	$ (452,900)	$ —	$ —
6.875% senior notes due 2018	$ (449,605)	$ (403,425)	$ (449,579)	$ (452,430)
7.20% senior notes due 2028	$ (249,921)	$ (212,600)	$ (249,918)	$ (253,150)

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.

Commodity price swap and collar contracts, interest rate swaps and foreign currency swap contracts. The fair value of commodity price swap and collar contracts, interest rate swaps and foreign currency contracts are estimated from quotes provided by the counterparties to these derivative contracts and represent the estimated amounts that the Company would expect to receive or pay to settle the derivative contracts. See Note J for a description of each of these types of derivatives, including whether the derivative contract qualifies for hedge accounting treatment or is considered a speculative derivative contract.

Financial assets. The carrying amounts of the trading securities approximate fair value due to the short maturity of these instruments. The fair value of the notes receivable approximates the carrying value at December 31, 2007 due to the adequacy of collateral security and interest yields. The current portion of the notes receivable, amounting to $3.6 million and $5.1 million as of December 31, 2007 and 2006, respectively, is included in other current assets, net in the Company's Consolidated Balance Sheets. The trading securities and the noncurrent portions of the notes receivable are included in other assets, net in the Company's Consolidated Balance Sheets. The Canadian escrow deposit account is a deposit account denominated in Canadian dollars. The carrying value of this account is 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 is included in other current assets in the Company's Consolidated Balance Sheet.

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Long-term debt. The carrying amount of borrowings outstanding under the Company's credit facility approximates fair value because these instruments bear 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.

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, 2007 and 2006:

	December 31, 2007	2006
	(in thousands)	
Outstanding debt principal balances:		
Credit facility	$ 1,113,000	$ 328,000
8.25% senior notes due 2007	—	32,075
6.50% senior notes due 2008	3,777	3,777
5.875% senior notes due 2012	6,110	6,110
5.875% senior notes due 2016	526,875	526,875
6.65% senior notes due 2017	500,000	—
6.875% senior notes due 2018	450,000	450,000
7.20% senior notes due 2028	250,000	250,000
	2,849,762	1,596,837
Issuance discounts and premiums, net	(91,111)	(96,284)
Net deferred fair value hedge losses	(3,160)	(3,391)
Total long-term debt	$ 2,755,491	$ 1,497,162

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, 2007, the Company had $1.1 billion of outstanding borrowings under the Credit Facility and had $80.0 million of undrawn letters of credit under the Credit Facility, leaving the Company with $307.0 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 (.125 percent per annum at December 31, 2007).

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 lenders

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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, 2007, the Company was in compliance with all of its debt covenants.

Senior notes. During May 2006, the Company issued $450 million of 6.875% senior notes due 2018 and received proceeds, net of issuance discount and underwriting cost, of $447.4 million.

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 matured and were repaid.

Senior convertible notes. During 2006, holders of the $100 million of 4 3/4% Senior Convertible Notes 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 million increase to stockholders' equity.

During January 2008, the Company issued $500 million principal amount of 2.875% convertible senior notes due 2038 (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.

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:

- Following defined periods during which the reported sales price of the Company's common stock exceeds 130 percent of the base conversion price (initially $72.60 per share);
- 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.

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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.

Pioneer Southwest credit facility. In October 2007, Pioneer Southwest entered into a $300 million unsecured revolving credit facility ("PSE Credit Agreement"), as amended, with a syndicate of banks. The PSE Credit Agreement would mature five years following the closing of Pioneer Southwest's initial public offering of limited partner interests and would contain certain financial covenants that would be applicable to it, including (i) the maintenance of a maximum leverage ratio of not more than 3.5 to 1.0, (ii) an interest coverage ratio (representing a ratio of EBITDAX 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 oil and gas assets to total debt of at least 1.75 to 1.0. Because of the net present value covenant, borrowings under the PSE Credit Agreement would be expected to be initially limited to approximately $150 million. It is a condition to the obligations of the lenders under the PSE Credit Agreement that Pioneer Southwest complete the offering. Pioneer Southwest is seeking an extension of the facility from the lenders. There can be no assurance that the lenders will agree to an extension, or if they do agree, that the terms of the facility will remain unchanged. If Pioneer Southwest were to seek a replacement facility, there can be no assurance that it would be able to do so or if it were successful, that the terms would be as favorable to Pioneer Southwest as the terms under the PSE Credit Agreement. See Note W for additional information on the Pioneer Southwest initial public offering.

Early extinguishment of debt. During 2006, the Company repurchased $346.2 million of its outstanding $350 million of 6.50% senior notes due 2008 (the "6.50% Notes"). The Company recognized a charge of $8.1 million in 2006 associated with the early extinguishment of the 6.50% Notes, which is included in other expense in the accompanying Consolidated Statements of Operations. During 2005, the Company (i) redeemed the remaining principal amounts of its outstanding 9 5/8% senior notes due 2010 and its 7.50% senior notes due 2012 of $64.0 million and $16.2 million, respectively, and (ii) accepted tenders to purchase for cash $188.4 million in principal amount of its 5 7/8% senior notes due 2012. Consequently, the Company recognized a charge for the early extinguishment of debt of $26.5 million included in other expense in the accompanying Consolidated Statements of Operations on these redemptions and tenders for 2005.

Principal maturities. Principal maturities of long-term debt at December 31, 2007, are as follows (in thousands):

2008	$ 3,777
2009	$ —
2010	$ —
2011	$ —
2012	$ 1,119,110
Thereafter	$ 1,726,875

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Interest expenses. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Cash payments for interest	$ 139,624	$ 114,745	$ 129,769
Accretion/amortization of discounts or premiums on loans	6,707	6,096	5,286
Accretion of discount on derivative obligations	7,306	2,529	—
Accretion of discount on postretirement benefit obligations (see Note H)	1,150	1,037	900
Amortization of net deferred hedge (gains) losses (see Note J)	434	14	(4,052)
Amortization of capitalized loan fees	1,452	1,366	2,265
Net changes in accruals	11,149	(6,571)	(7,092)
Interest incurred	167,822	119,216	127,076
Less capitalized interest	(32,552)	(12,166)	(1,089)
Total interest expense	$ 135,270	$ 107,050	$ 125,987

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, drilling 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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 1,835	$ 1,635	$ 1,526
Reimbursement of general and administrative expenses	$ 364	$ 348	$ 348

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 $1.4 million, $1.3 million and $1.2 million for the years ended December 31, 2007, 2006 and 2005, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. ("Pioneer 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 Pioneer 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 of not less than two percent nor more

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than 30 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer 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, 2007, 2006 and 2005, the Company recognized compensation expense of $10.9 million, $9.3 million and $8.0 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, 2007:

Approved and authorized awards	4,600,000
Awards issued after May 3, 2006	(869,739)
Awards available for future grant	3,730,261

For the 2007-2008 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. Prior to adoption of SFAS 123(R), the Company recorded $56.2 million of deferred compensation associated with restricted stock awards in stockholders' equity during 2005. 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).

As of December 31, 2007, there was approximately $34.9 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, 2007, 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 period of less than three years.

Restricted stock awards. During 2007, 2006 and 2005 the Company issued 831,799, 736,642 and 1,411,269, respectively, restricted shares of the Company's common stock as compensation to directors, officers and employees of the Company.

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The following table reflects the outstanding restricted stock awards as of December 31, 2007, 2006 and 2005 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2007		2006		2005	
	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	2,126,547	$ 39.32	1,966,223	$ 36.90	1,447,987	$ 28.46
Shares granted	831,799	$ 40.61	736,642	$ 43.44	1,411,269	$ 39.79
Shares forfeited	(96,811)	$ 41.12	(190,538)	$ 39.32	(174,046)	$ 33.99
Lapse of restrictions	(702,941)	$ 35.74	(385,780)	$ 34.84	(718,987)	$ 26.26
Outstanding at end of year	2,158,594	$ 40.90	2,126,547	$ 39.32	1,966,223	$ 36.90

Stock option awards. The Company did not grant any stock options during 2007, 2006 or 2005.

A summary of the Company's stock option plans as of December 31, 2007, 2006 and 2005, and changes during the years then ended, are presented below:

	Year Ended December31,					
	2007		2006		2005	
	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price
Nonstatutory stock options:						
Outstanding at beginning of year	1,601,495	$ 20.50	2,685,398	$ 20.32	5,180,584	$ 18.60
Options forfeited	(5,790)	$ 33.54	(267,851)	$ 22.60	(65,190)	$ 22.94
Options exercised	(620,960)	$ 19.62	(816,052)	$ 19.22	(2,429,996)	$ 15.95
Outstanding at end of year	974,745	$ 20.99	1,601,495	$ 20.50	2,685,398	$ 20.32
Exercisable at end of year	974,745	$ 20.99	1,601,495	$ 20.50	2,382,714	$ 19.74

The following table summarizes information about the Company's stock options outstanding and exercisable at December 31, 2007:

Range of Exercise Price	Options Outstanding and Exercisable Number Outstanding at December 31, 2007	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value at December 31, 2007 (in thousands)
$5-$11	67,114	2.5 years	$ 10.75	$ 2,556
$12-$18	381,443	1.6 years	$ 17.52	11,945
$19-$26	526,188	2.2 years	$ 24.80	12,650
	974,745			$ 27,151

Performance unit awards. During 2007, the Company awarded performance units ("Performance Units") to the Company's corporate officers under the Long-Term Incentive Plan. The 2007 Performance Unit awards were for 145,820 aggregate units, of which 142,326 units remain outstanding as of December 31, 2007, after cancellation of 2,677 units for forfeitures and 817 units lapsed by their terms during 2007. A maximum of 355,815 shares of the Company's common stock may be issued under the Performance Units 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 period will be based on a total share return ("TSR") market objective ranking the Company's TSR against a defined peer group's individual TSRs.

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The aggregate fair value of the outstanding Performance Units is $6.1 million, based on a per-unit fair value of $42.36 as of the grant date, which amount was determined using the Monte Carlo simulation method and is being recognized as compensation expense ratably over the service period. The Company recognized $1.8 million of compensation expense attributable to the Performance Units during 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, 2007 and 2006, the Company recognized compensation expense of $606 thousand and $669 thousand, respectively, associated with the ESPP.

Postretirement Benefit Obligations

At December 31, 2007 and 2006, the Company had recorded $10.5 million and $19.8 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, 2007 or 2006. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

At December 31, 2007, the accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $6.6 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 6.25 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 in 2008, declining to five percent in 2013 and thereafter, and annual dental cost escalation trends of seven percent in 2008, 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.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Beginning accumulated post retirement benefit obligations	$ 19,837	$ 18,576	$ 15,534
Net benefit payments	(968)	(1,234)	(1,393)
Service costs	1,036	816	324
Net actuarial losses (gains)	(10,561)	642	3,211
Accretion of interest	1,150	1,037	900
Ending accumulated postretirement benefit obligations	$ 10,494	$ 19,837	$ 18,576

Estimated benefit payments and service/interest costs associated with the plans for the year ending December 31, 2008 are $1.2 million and $.8 million, respectively.

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The Company adopted the provisions of 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 future 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 $42.0 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.

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, NA, ("JP Morgan") as Trustee of the Mesa Offshore 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 ("Wiegand") each filed a Petition in Intervention in the lawsuit to assert the same claims as MOSH Holding, L.P. ("MHLP"). MHLP, Dagger-Spine and Wiegand (collectively, "Plaintiffs") are unitholders in the Trust, which was created in 1982 as the sole limited partner in a partnership that holds an overriding royalty interest in certain oil and gas leases offshore Louisiana and Texas. 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. The relief sought by the Plaintiffs includes monetary and punitive damages and certain equitable relief, including an accounting of expenses, a setting aside of certain farmouts, 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. These motions are pending before the court.

On October 26, 2007, the Plaintiffs and JP Morgan announced before the Court that they had reached a tentative settlement of claims pending between them. As part of the tentative settlement, the Plaintiffs and JP Morgan also announced their intention to seek Court appointment of a temporary trustee. The Company objected to the terms of the proposed settlement and to the proposed substitution of a temporary trustee in place of JP Morgan. In addition, on December 20, 2007, Pioneer filed a cross-claim against JP Morgan seeking, among other things, to prevent JP Morgan from resigning as Trustee on the grounds that the Trust Indenture requires that the Trust must be liquidated and terminated. On January 22, 2008, the Court issued an order denying the settlement and proposed trustee substitution, as well as the Company's cross-claim.

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

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be adverse to the Company and if so, whether such an outcome will materially and negatively impact the Company's liquidity, financial position or future results of operations.

Equatorial Guinea Block H Arbitration. On June 14, 2007, a subsidiary of the Company ("Pioneer EG") commenced arbitration in London, England against Roc Oil (Equatorial Guinea) Company ("ROC EG"), Atlas Petroleum International Limited ("Atlas") and Osborne Resources Limited ("Osborne") to determine the parties' respective rights and obligations under a joint operating agreement relating to well operations in Block H in deepwater Equatorial Guinea. ROC, Atlas and Osborne have, in turn, brought counterclaims against Pioneer EG in respect to alleged breaches of the farm-in agreements relating to Block H. In late 2006, the Republic of Equatorial Guinea ratified a new hydrocarbons law, which among other things, appears to entitle Equatorial Guinea to increase substantially its carried interest in all concessions, including Block H, either directly or through the National Oil Company. In addition, drilling costs for the well have increased significantly beyond those originally anticipated.

Given these and other factors, Pioneer EG maintains that it does not have an obligation to approve the drilling of a well on the block. The view of the other parties is that Pioneer EG does not have the right to prevent the drilling of the well or to refuse to pay its share of the costs thereof. ROC EG, Atlas and Osborne have also notified Pioneer EG that they reserve the right to claim damages should they suffer any loss, including any loss suffered if the underlying production sharing contract is terminated by Equatorial Guinea.

The parties have consolidated their respective claims under the joint operating agreement and the farm-in agreements into a single arbitration to be conducted in London, England during 2008. Pioneer EG intends vigorously to assert its position in the arbitration. 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 and negatively impact the Company's liquidity, financial position or future results of operations.

*Environmental Protection Agency Investigation.*On November 4, 2005, the Company learned from the U.S. Environmental Protection Agency that the agency was conducting a criminal investigation into a 2003 spill that occurred at a Company-operated drilling rig located on an ice island offshore Harrison Bay, Alaska. The investigation is being conducted in conjunction with the U.S. Attorney's Office for the District of Alaska. The spill was previously investigated by the Alaska Department of Environmental Conservation ("ADEC") and, following completion of a clean up, the ADEC issued a letter stating its determination that, at that time, the site did not pose a threat to human health, safety or welfare, or the environment. The Company is fully cooperating with the government's investigation. The Company cannot predict whether the outcome of this investigation will be adverse to the Company and if so, whether such an outcome will materially and negatively impact the Company's liquidity, financial position or future results of operations.

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.

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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, 2007, 2006 and 2005 were approximately $47.0 million, $46.8 million and $64.5 million, respectively, which includes $1.7 million, $9.8 million and $27.1 million, respectively, associated with discontinued operations. Future minimum lease commitments under noncancellable operating leases at December 31, 2007 are as follows (in thousands):

2008	$ 28,913
2009	$ 12,910
2010	$ 13,216
2011	$ 11,873
2012	$ 10,623
Thereafter	$ 75,907

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.

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 205 million cubic feet ("MMcf") of gross gas volumes per day during 2007, including fuel commitments, and will average approximately 226 MMcf per day of gross gas volume during 2008, decreasing to approximately 219 MMcf per day per day during 2009, 204 MMcf 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.

The Uinta Basin transportation commitments commenced during June 2007 and averaged approximately 5 MMcf of gross gas volumes per day during the second half of 2007, including fuel commitments, and will average approximately 8 MMcf per day during 2008, 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, 2007 are as follows (in thousands):

2008	$ 26,086

2009	$ 25,972
2010	$ 24,635
2011	$ 21,567
2012	$ 14,536
Thereafter	$ 31,967

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 hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the present value difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income (loss), which is later transferred to earnings when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as

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hedges, as well as the ineffective portion of changes in the fair value of hedge derivatives, are recorded in earnings. 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.

Fair value hedges. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate swap contracts with the objective of reducing costs of capital.

As of December 31, 2007, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included a $3.2 million reduction in the carrying value attributable to net deferred hedge losses on terminated fair value hedges that are being amortized as net increases to interest expense over the original terms of the terminated agreements. The amortization of net deferred hedge losses on terminated interest rate swaps increased the Company's reported interest expense by $434 thousand and $14 thousand during the years ended December 31, 2007 and 2006, as compared to net deferred gains amortization, which reduced the Company's reported interest expense by $4.1 million during the year ended December 31, 2005.

The following table sets forth, as of December 31, 2007, the scheduled amortization of net deferred hedge losses on terminated interest rate hedges (including terminated fair value and cash flow hedges) that will be recognized as increases to the Company's future interest expense:

	Net deferred interest rate hedge losses		
	Fair Value	Cash Flow	Total
	(in thousands)		
2008	$ 257	$ 231	$ 488
2009	$ 281	$ 260	$ 541
2010	$ 307	$ 293	$ 600
2011	$ 337	$ 328	$ 665
2012	$ 369	$ 366	$ 735
Thereafter	$ 1,609	$ 1,594	$ 3,203

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, 2007, all of the Company's open commodity hedges are 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.

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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 hedged in barrels ("Bbl") underlying the Company's outstanding oil hedge contracts and the weighted average NYMEX prices per Bbl for those contracts as of December 31, 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily oil production hedged:					
2008 – Collar Contracts					
Volume (Bbl)	3,000	3,000	3,000	3,000	3,000
Price per Bbl	$ 65.00-$80.80	$ 65.00-$80.80	$ 65.00-$80.80	$ 65.00-$80.80	$ 65.00-$80.80
2008 – Swap Contracts					
Volume (Bbl)	15,250	15,250	15,250	15,250	15,250
Price per Bbl	$ 61.36	$ 61.36	$ 61.36	$ 61.36	$ 61.36
2009 – Collar Contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl	$ 65.00-$76.50	$ 65.00-$76.50	$ 65.00-$76.50	$ 65.00-$76.50	$ 65.00-$76.50
2009 – Swap Contracts					
Volume (Bbl)	8,000	8,000	8,000	8,000	8,000
Price per Bbl	$ 71.57	$ 71.57	$ 71.57	$ 71.57	$ 71.57
2010 – Swap Contracts					
Volume (Bbl)	4,000	4,000	4,000	4,000	4,000
Price per Bbl	$ 71.46	$ 71.46	$ 71.46	$ 71.46	$ 71.46

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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
Average price reported per Bbl	$ 66.08	$ 65.51	$ 38.61

Average price realized per Bbl	$ 70.91	$ 63.42	$ 53.72
VPP increase to oil revenue (in millions)	$ 109.7	$ 116.1	$ —
Decrease to oil revenue from hedging activity (in millions) (a)	$ 154.1	$ 97.6	$ 176.6

(a) Excludes hedge losses of $12.3 million and $52.0 million attributable to discontinued operations for the years ended December 31, 2006 and 2005, respectively.

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Natural gas liquids 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 hedged in Bbls under outstanding NGL hedge contracts and the weighted average Mont Belvieu prices per Bbl for those contracts at December 31, 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily NGL production hedged:					
2008 – Swap Contracts					
Volume (Bbl)	500	500	500	500	500
Price per Bbl	$ 44.33	$ 44.33	$ 44.33	$ 44.33	$ 44.33
2009 – Swap Contracts					
Volume (Bbl)	500	500	500	500	500
Price per Bbl	$ 41.75	$ 41.75	$ 41.75	$ 41.75	$ 41.75
2010 – Swap Contracts					
Volume (Bbl)	500	500	500	500	500
Price per Bbl	$ 39.63	$ 39.63	$ 39.63	$ 39.63	$ 39.63

The Company was not party to any NGL contracts for production occurring during the years ended December 31, 2007, 2006 and 2005.

Gas prices. The Company employs a policy of hedging 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 hedged in million British thermal units ("MMBtu") under outstanding gas hedge contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily gas production hedged (a):					
2008 – Swap Contracts					
Volume (MMbtu)	132,500	132,500	132,500	119,239	129,167
Price per MMBtu	$ 7.89	$ 7.48	$ 7.48	$ 7.56	$ 7.60
2009 – Swap Contracts					

Volume (MMbtu)	32,500	2,500	2,500	2,500	9,897
Price per MMBtu	$ 7.92	$ 7.55	$ 7.55	$ 7.55	$ 7.85
2010 – Swap Contracts					
Volume (MMbtu)	2,500	2,500	2,500	2,500	2,500
Price per MMBtu	$ 7.33	$ 7.33	$ 7.33	$ 7.33	$ 7.33

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(a) Subsequent to December 31, 2007 and through February 15, 2008, the Company entered into additional swap contracts for approximately 69,945 MMBtu per day of the Company's 2008 production at an average price of $7.28 per MMBtu.

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

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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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
Average price reported per Mcf	$ 7.26	$ 6.15	$ 6.94
Average price realized per Mcf	$ 6.04	$ 5.96	$ 7.26
VPP increase to gas revenue (in millions)	$ 71.6	$ 74.2	$ 75.8
Increase (decrease) to gas revenue from hedging activity (in millions) (a)	$ 70.6	$ (53.6)	$ (108.2)

(a) Excludes hedge gains (losses) of $28.1 million, $(1.2) million and $(94.7) million attributable to discontinued operations for the year ended December 31, 2007, 2006 and 2005, respectively.

Interest rate. During March 2007, the Company entered into treasury lock contracts and designated the contracts as cash flow hedges of the forecasted interest rate risk associated with the coupon rate on the Company's 6.65% Notes, which were issued in March 2007. The Company terminated these contracts for a loss of $1.5 million, which was recorded in accumulated other comprehensive income (loss) – net deferred hedge losses, net of tax ("AOCI – Hedging"). The Company did not realize any ineffectiveness in connection with the treasury lock contracts. See Note F for information regarding the 6.65% Notes.

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 terminate during February 2010 and $200 million during February 2011.

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). The following table sets forth the hedge ineffectiveness income (loss) attributable to continuing operations recognized in the Consolidated Statements of Operations for the years ended December 31, 2007, 2006 and

2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in millions)		
Interest and other income	$ —	$ 7.4	$ —
Other expense	(2.1)	10.6	(29.8)
Total ineffectiveness (a)	$ (2.1)	$ 18.0	$ (29.8)

(a) Excludes hedge ineffectiveness income (loss) attributable to discontinued operations of $7.4 million and $(22.6) million during 2006 and 2005, respectively.

AOCI - Hedging. As of December 31, 2007 and 2006, AOCI - Hedging represented net deferred losses of $228.3 and $167.2 million, respectively. 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

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flow interest rate hedges) and $132.8 million of associated net deferred tax benefits. The AOCI - Hedging balance as of December 31, 2006 was comprised of $71.0 million of net deferred losses on the effective portions of open cash flow hedges, $193.7 million of net deferred losses on terminated cash flow hedges (including $1.7 million of net deferred losses on terminated cash flow interest rate hedges) and $97.5 million of associated net deferred tax benefits. The increase in AOCI - Hedging 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 losses 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 losses on terminated cash flow hedges are fixed.

During the year ending December 31, 2008, based on current estimates of future commodity prices, the Company expects to reclassify $157.2 million of net deferred losses associated with open commodity hedges and $98.9 million of net deferred losses on terminated commodity hedges from AOCI - Hedging to oil and gas revenues. The Company also expects to reclassify approximately $94.7 million of net deferred income tax benefits associated with commodity hedges during the year ending December 31, 2008 from AOCI - Hedging to income tax benefit.

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, 2007, the scheduled amortization of net deferred losses on terminated commodity hedges that will be recognized as decreases to the Company's future oil and gas revenues:

	First Quarter (in thousands)	Second Quarter	Third Quarter	Fourth Quarter	Total
2008 net deferred hedge losses	$ 26,858	$ 24,027	$ 23,873	$ 24,102	$ 98,860
2009 net deferred hedge losses	$ 2,330	$ 232	$ 230	$ 822	$ 3,614
2010 net deferred hedge losses	$ 667	$ 620	$ 578	$ 539	$ 2,404
2011 net deferred hedge losses	$ 873	$ 889	$ 902	$ 906	$ 3,570
2012 net deferred hedge losses	$ 810	$ 791	$ 783	$ 772	$ 3,156

Non-hedge derivatives. 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 are 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 mature during May 2008 and are for a notional amount of approximately $131.0 million USD. The Company recognized a loss of $1.5 million associated with these derivatives, which amount is included in discontinued operations in the Company's accompanying Consolidated Statement of Operations for 2007.

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 receivable and the general economic condition of its purchasers and, depending on facts and circumstances, may require purchasers to provide collateral or otherwise secure their

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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.

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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
Plains Marketing LP	14 %	12 %	7 %
Oneok Resources	11 %	12 %	6 %
Occidental Energy Marketing, Inc.	11 %	11 %	9 %

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, 2007, 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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Beginning asset retirement obligations	$ 225,913	$ 157,035	$ 120,879
Liabilities assumed in acquisitions	4,751	981	3,183
New wells placed on production and changes in estimates (a)	91,067	122,685	57,405
Disposition of wells	(30,599)	(44,042)	(23,101)

Liabilities settled	(95,980)	(16,219)	(9,508)
Accretion of discount on continuing operations	7,028	3,726	3,349
Accretion of discount on discontinued operations	1,767	1,904	4,527
Currency translation	4,237	(157)	301
Ending asset retirement obligation	$ 208,184	$ 225,913	$ 157,035

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(a) Includes, for the years ended December 31, 2007, 2006 and 2005, respectively, a $66.0 million, $75.0 million and a $39.8 million increase in the abandonment estimate of the East Cameron facilities that were destroyed by Hurricane Rita, which 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 $86.9 million and $111.2 million as of December 31, 2007 and 2006, 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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Alaskan Petroleum Production Tax credits	$ 74,861	$ —	$ —
Alaskan Exploration Incentive Tax credits	—	5,570	—
Royalty obligation accrual adjustment	4,816	—	—
Sales and other tax refunds	3,730	645	1,792
Minority interest in subsidiary net loss (see Note B)	2,778	4,892	5,206
Interest income	3,038	14,369	1,510
Other income	3,210	3,276	1,714
Deferred compensation plan income	1,247	879	500
Foreign currency remeasurement and exchange gains (a)	6	361	236
Business interruption insurance claim (see Note U)	—	7,647	14,200
Bad debt recoveries	—	2,130	—
Credit card rebate	975	837	835
Seismic data sales	—	413	467
Derivative ineffectiveness (see Note J)	—	7,371	—
Total interest and other income	$ 94,661	$ 48,390	$ 26,460

(a) The Company's operations in Argentina, Canada and Africa periodically recognize 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, 2007, 2006 and 2005, the Company completed asset divestitures for net proceeds of $553.7 million, $1.6 billion and $1.2 billion, respectively. Associated therewith, the Company recorded gains (losses) on disposition of assets in continuing operations of $(2.2) million, $(6.5) million and $60.1 million during the years ended December 31, 2007, 2006 and 2005, respectively, and gains of $100.2 million, $731.8 million and $166.5 million in discontinued operations in 2007, 2006 and 2005, respectively. The following represent 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 Statement of Cash Flows for the year ended December 31, 2007, includes only $392.9 million of proceeds from disposition of assets, net of cash sold 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.

Nigeria. In June 2007, the Company entered into an agreement to divest its interest in a subsidiary (owned 59 percent by the Company, the "Nigeria Subsidiary") that held an interest in the deepwater Nigerian Block 320. The agreement was subject to governmental approval. The governmental approval was not obtained by the deadline and as a result, Pioneer terminated the agreement. Also, as a result of due diligence efforts that emerged as part of the Company's compliance efforts, and with assistance from outside counsel, the Company determined that it could not, consistent with its legal obligations, fund or approve future operations in connection with Block 320. As a

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result, during the third quarter of 2007 the Company engaged in a process to withdraw from the production sharing contract relating to Block 320 and related agreements. As a part of this process the Company disposed of its shares in the Nigeria Subsidiary to an unaffiliated third party. As a result, the Company no longer owns any interest in the Nigeria Subsidiary or Block 320 and will not fund or participate in any future operations in connection with Block 320. See Note S for additional information regarding the Nigerian impairment.

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.

Volumetric production payments. During 2005, the Company sold three VPPs for proceeds of $892.6 million. No gain or loss was recognized. See Note T for additional information.

Canadian and Gulf of Mexico Shelf divestitures. During 2005, the Company sold its interests in the Martin Creek, Conroy Black and Lookout Butte areas in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million and certain assets on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 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.

East Texas divestiture. During the year ended December 31, 2005, the Company sold its interests in certain East Texas properties for $25.3 million of net cash proceeds with no corresponding gain or loss recognized.

Gabon divestiture. In 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owned the Company's interest in the Olowi block for $47.9 million of net proceeds. A $47.5 million gain was recognized with no associated income tax effect either in Gabon or the United States. During 2007, Pioneer relinquished its rights to receive additional payments for production discovered from deeper reservoirs on the block in consideration for a release of certain obligations.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Contingency accrual adjustments (see Note I)	$ 14,750	$ 10,119	$ 9,455
Idle drilling equipment cost	8,682	275	—
Bad debt expense	5,119	4,733	367
Well servicing operations	3,245	1,722	—
Minority interest in subsidiaries' net income	2,426	2,629	3,482
Derivative ineffectiveness (see Note J)	2,135	(10,595)	29,829
Other charges	1,125	3,287	18
Loss on early extinguishment of debt (see Note F)	—	8,076	26,465
Noncompete agreement amortization	—	1,670	3,914
Non-hedge derivative losses	—	6,517	3,860
Insurance charges	—	4,000	—
Abandoned acquisitions and divestitures	3,385	1,775	13
Foreign currency remeasurement and exchange losses (a)	184	580	109
Contingency settlements and costs	1,363	1,489	—
Postretirement benefit obligation revaluation	(10,562)	642	3,211
Total other expense	$ 31,852	$ 36,919	$ 80,723

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(a) The Company's operations in Argentina, Canada and Africa periodically recognize 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 of $57.0 million, $153.2 million and $41.4 million were made during the years ended December 31, 2007, 2006 and 2005, 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, local and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2007 and 2006, the Company's valuation allowances (relating primarily to foreign tax jurisdictions) were $24.8 million and $94.7 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 foreign, federal and state 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.

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 2002. In December 2007, the Internal Revenue Service ("IRS") completed an examination of the Company's 2004 U.S. federal income tax return. The Company agreed to proposed IRS adjustments that resulted in a $0.6 million deferred tax benefit and a $1.8 million reduction of current income taxes receivable. Subsequent amendments of federal and state returns relating to these audit adjustments are not expected to have a significant effect on the Company's future results of operations or financial position. In addition, the Company's 2003 through 2005 state income tax returns in Colorado are currently under audit and the Tunisian government is concluding an audit of the Company's 2002 through 2005 income tax returns for the Adam Concession. No significant adjustments have been proposed in Colorado or Tunisia.

In February 2007, the Republic of South Africa passed legislation that included significant new tax benefits for oil and gas activities. Effective January 1, 2007, the Company is allowed a deduction from oil and gas income equal to 200 percent of exploration expenditures and 150 percent of development expenditures. Pursuant to the new tax legislation, the Company recorded a $15.7 million tax benefit for 2007 associated with capital expenditures incurred after the effective date, primarily related to the South Coast Gas project.

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 recorded $18.9 million of U.S. deferred tax expense in 2007 associated with the results of operations of its South African subsidiaries.

During the second quarter of 2007, the Company announced actions to exit Nigeria. During the third and fourth quarters of 2007, the Company completed its disposal of the subsidiary holding Block 320 and relinquished

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all its rights in Block 256. This exit from Nigeria allows the Company to deduct in the U.S. the cumulative expenditures associated with its past Nigerian activities and accordingly the Company has recognized a $40.9 million tax benefit in 2007. Additionally, the Company has relinquished all remaining rights in Gabon and has written off costs associated with Block H in Equatorial Guinea generating a $13.8 million tax benefit in 2007.

The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Income from continuing operations	$ 112,645	$ 141,021	$ 149,231
Income from discontinued operations	(17,972)	295,501	215,614
Changes in goodwill	961	(1,742)	(7,255)
Changes in stockholders' equity:			
Net deferred hedge gains (losses)	(28,304)	193,719	(166,572)
Tax benefits related to stock-based compensation	(3,908)	(4,247)	(18,752)
Translation adjustment	644	8,421	3,685
	$ 64,066	$ 632,673	$ 175,951

The Company's income tax provision (benefit) attributable to income from continuing operations consisted of the following for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Current:			
U.S. federal	$ (60,320)	$ (54,004)	$ 13,104
U.S. state and local	331	(52)	(254)
Foreign	48,815	33,316	37,002
	(11,174)	(20,740)	49,852
Deferred:			
U.S. federal	132,246	126,215	90,988
U.S. state and local	6,576	18,438	3,038
Foreign	(15,003)	17,108	5,353

123,819	161,761	99,379
$ 112,645	$ 141,021	$ 149,231

Income from continuing operations before income taxes consists of the following for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in thousands)		
U.S. Federal	$ 309,262	$ 235,049	$ 194,993
Foreign	45,362	56,189	138,543
	$ 354,624	$ 291,238	$ 333,536

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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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
State income taxes (net of federal benefit)	2.2	1.7	1.1
U.S. valuation allowance changes	0.1	0.3	0.2
Foreign valuation allowances	6.9	8.8	0.3
Rate differential on foreign operations	4.8	4.7	2.8
Change in statutory rates	(0.2)	1.0	0.1
West Africa exit (U.S. federal benefit)	(15.4)	—	—
South Africa expenditures uplift - 50% of development capital expenditures	(4.4)	—	—
South Africa earnings (U.S. federal income taxes)	5.3	—	—
Gabon investment deduction	—	—	7.4
Gabon tax free book gain	—	—	(4.7)
Repatriation of foreign earnings	—	—	2.0
Conversion of senior convertible notes	—	(2.7)	—
Other	(2.5)	(0.4)	0.5
Consolidated effective tax rate	31.8	48.4	44.7

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, 2007 and 2006:

	December 31,	
	2007	2006
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 103,918	$ 102,251
Alternative minimum tax credit carryforwards	41,668	—
Net deferred hedge losses	132,763	97,717
Asset retirement obligations	71,396	76,509
Other	47,457	99,330
Total deferred tax assets	397,202	375,807
Valuation allowances	(24,838)	(94,745)

Net deferred tax assets	372,364	281,062
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	1,317,571	1,232,025
State taxes and other	166,134	138,272
Total deferred tax liabilities	1,483,705	1,370,297
Net deferred tax liability	$ (1,111,341)	$ (1,089,235)

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At December 31, 2007, 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 NOLs
2009	$ 29,999	$ 32,003	$ —	$ —
2010	49,858	47,854	—	—
2020	5,588	5,055	—	—
2021	53	—	—	—
Indefinite	—	—	160,504	54,896
	$ 85,498	$ 84,912	$ 160,504	$ 54,896

The remaining $85.5 million of the U.S. NOLs and $84.9 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 four years. During the years ended December 31, 2006 and 2005, the Company utilized $409.8 million and $311.6 million of NOLs, respectively, for U.S. federal income tax purposes. For the year ended December 31, 2007, the Company generated a tax loss of approximately $272 million, which will be carried back and utilized in 2006.

The Company's income tax provision (benefit) attributable to income from discontinued operations consisted of the following for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31, 2007 (in thousands)	2006	2005
Current:			
U.S. federal	$ —	$ 145,623	$ 2,438
U.S. state and local	—	1,421	104
Foreign	4,915	4,633	5,290
	4,915	151,677	7,832
Deferred:			
U.S. federal	(21,612)	144,387	153,030
U.S. state and local	—	6,449	6,558

Foreign	(1,275)	(7,012)	48,194
	(22,887)	143,824	207,782
	$ (17,972)	$ 295,501	$ 215,614

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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Basic income from continuing operations	$ 241,979	$ 150,217	$ 184,305
Interest expense on convertible notes, net of tax	—	1,903	3,207
Diluted income from continuing operations	$ 241,979	$ 152,120	$ 187,512

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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Weighted average common shares outstanding (a):			
Basic	120,158	124,359	137,110
Dilutive common stock options	433	747	1,136
Restricted stock awards	1,045	989	844
Contingently issuable - performance shares (b)	23	—	—
Convertible notes dilution (c)	—	1,513	2,327
Diluted	121,659	127,608	141,417

(a) In 2007, the Board authorized share repurchases of up to $750 million of the Company's common stock. Through December 31, 2007, the Company had repurchased $212.8 million of common stock under this 2007 authorized program. During 2005, the Board approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock, $640.7 million of which was completed in 2005 and $345.3 million of which was completed in 2006.

(b) During 2007, a target amount of 145,820 performance units were awarded of which amount 2,677 performance units have since been forfeited and canceled, 817 units have been earned and 142,326 remain outstanding. At December 31, 2007, based on the performance criteria met, the Company included 22,880 of performance units in weighted average shares outstanding for the year ended December 31, 2007.

(c) During 2006, holders of the $100 million of 4 3/4% Senior Convertible Notes exercised their conversion rights.

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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. During 2005, the Company sold certain Canadian and United States oil and gas properties having carrying values of $58.9 million and $31.4 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, 2007, 2006 and 2005. 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, 2007:						
Revenues and other income:						
Oil and gas	$ 1,552,780	$ 81,730	$ 106,341	$ —	$ —	$ 1,740,851
Interest and other	—	—	—	—	94,661	94,661
Gain (loss) on disposition of assets, net	844	—	—	—	(3,007)	(2,163)
	1,553,624	81,730	106,341	—	91,654	1,833,349
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 long-lived assets	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
Other	—	—	—	—	31,852	31,852
	1,022,572	39,997	32,551	51,200	332,405	1,478,725
Income (loss) from continuing operations before income taxes	531,052	41,733	73,790	(51,200)	(240,751)	354,624
Income tax benefit (provision)	(196,489)	(12,103)	(45,545)	—	141,492	(112,645)
Income (loss) from continuing operations	$ 334,563	$ 29,630	$ 28,245	$ (51,200)	$ (99,259)	$ 241,979
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	—	—	—	—	48,390	48,390
Loss on disposition of assets, net	(451)	—	—	—	(6,008)	(6,459)
	1,301,578	99,309	57,602	—	42,382	1,500,871
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
Other	—	—	—	—	36,919	36,919
	805,829	38,766	21,845	55,205	287,988	1,209,633
Income (loss) from continuing operations before income taxes	495,749	60,543	35,757	(55,205)	(245,606)	291,238
Income tax benefit (provision)	(183,427)	(17,557)	(22,450)	—	82,413	(141,021)
Income (loss) from continuing operations	$ 312,322	$ 42,986	$ 13,307	$ (55,205)	$ (163,193)	$ 150,217

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	United States (in thousands)	South Africa	Tunisia	Other	Headquarters	Consolidated Total
Year ended December 31, 2005:						
Revenues and other income:						
Oil and gas	$ 1,144,163	$ 127,470	$ 67,250	$ —	$ —	$ 1,338,883
Interest and other	—	—	—	—	26,460	26,460
Gain on disposition of assets, net	12,114	—	—	47,532	417	60,063
	1,156,277	127,470	67,250	47,532	26,877	1,425,406
Costs and expenses:						
Oil and gas production	277,297	28,354	4,063	—	—	309,714
Depletion, depreciation and amortization	219,045	24,494	4,758	—	19,460	267,757
Impairment of long-lived assets	—	—	—	644	—	644
Exploration and abandonments	97,126	1,211	10,898	44,544	—	153,779
General and administrative	—	—	—	—	110,104	110,104
Accretion of discount on asset retirement obligation	—	—	—	—	3,349	3,349
Interest	—	—	—	—	125,987	125,987
Hurricane activity, net	39,813	—	—	—	—	39,813
Other	—	—	—	—	80,723	80,723
	633,281	54,059	19,719	45,188	339,623	1,091,870
Income (loss) from continuing operations before income taxes	522,996	73,411	47,531	2,344	(312,746)	333,536
Income tax benefit (provision)	(190,894)	(21,289)	(32,422)	—	95,374	(149,231)
Income (loss) from continuing operations	$ 332,102	$ 52,122	$ 15,109	$ 2,344	$ (217,372)	$ 184,305

Segment Assets:	**December 31, 2007** (in thousands)	**2006**	**2005**
United States	$ 7,932,366	$ 6,395,046	$ 5,899,637
Canada	—	547,012	363,773
Argentina	8,076	2,444	735,191
South Africa	294,491	176,789	64,071
Tunisia	216,221	72,142	59,125
West Africa	2,360	41,238	47,288

Headquarters	163,467	120,728	160,149
Total consolidated assets	$ 8,616,981	$ 7,355,399	$ 7,329,234

NOTE S. Impairment of Long-Lived 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 years ended December 31, 2007 and 2005, the Company recognized aggregate impairment charges of $26.2 million and $644 thousand, respectively.

Nigerian impairment. In June 2007, the Company entered into an agreement to divest its interest in a subsidiary (owned 59 percent by the Company, the "Nigeria Subsidiary") that held an interest in the deepwater Nigerian Block 320. The agreement was subject to governmental approval. The governmental approval was not

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obtained by the deadline and as a result, Pioneer terminated the agreement. Based on the terms of the agreement, which established the Company's estimate of fair value, the Company recorded a $12.2 million noncash impairment charge in the second quarter of 2007 to reduce the net basis to the estimated fair value. Also, as a result of due diligence efforts that emerged as part of the Company's compliance efforts, and with assistance from outside counsel, the Company determined that it could not, consistent with its legal obligations, fund or approve future operations in connection with Block 320. As a result, during the third quarter of 2007 the Company engaged in a process to withdraw from the production sharing contract relating to Block 320 and related agreements. As a part of this process, the Company disposed of its shares in the Nigeria Subsidiary to an unaffiliated third party and associated therewith, the Company recorded a reduction of $2.0 million to the previous noncash impairment charge. As a result, the Company no longer owns any interest in the Nigeria Subsidiary or Block 320 and will not fund or participate in any future operations in connection with Block 320.

Equatorial Guinea impairment. During the fourth quarter of 2007, the Company recorded a noncash 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 the ongoing arbitration among the parties participating in the Block H prospect. See Note I for additional information regarding the Block H arbitration.

United States impairment. During the second quarter of 2007, the Company recorded a $5.7 million noncash impairment provision to reduce the carrying values of certain proved oil and gas properties located in Louisiana. The impairment provision was determined in accordance with SFAS 144, and reduced the carrying values of the assets to their estimated fair value.

Gabon impairment. During 2005, the Company recognized noncash impairment charges of $644 thousand to reduce the carrying value of its Gabonese Olowi field assets as development of the discovery was canceled.

Piceance/Uinta Basins. During 2007, events and circumstances indicated that approximately $130.9 million of net assets in the Company's Piceance/Uinta area may have been partially impaired. However, the Company's estimate of undiscounted cash flows indicated that such carrying amounts were expected to be recovered. Nonetheless, it is reasonably possible that the estimate of undiscounted cash flows may change in the future resulting in the need to write down those assets to fair value.

NOTE T. Volumetric Production Payments

During 2005, the Company sold 27.8 MMBOE of proved reserves by means of three VPP agreements for net proceeds of $892.6 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to reduce outstanding indebtedness. The first VPP sold 58 Bcf of gas volumes over an expected five-year term that began in February 2005. The second VPP sold 10.8 million barrels ("MMBbls") of oil volumes over an expected seven-year term that began in January 2006. The third VPP sold 6.0 Bcf of gas volumes over an expected 32-month term that began in May 2005 and 6.2 MMBbls of oil volumes over an expected five-year term that began in January 2006.

The Company's VPPs represent limited-term overriding royalty interests in oil and gas reserves that: (i) entitle the purchaser to receive production volumes over a period of time from specific lease interests; (ii) are free and clear of all associated future production costs and capital expenditures; (iii) are nonrecourse to the Company (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfer title to the purchaser; and (v) allow the Company to retain the remaining reserves after the VPPs volumetric quantities have been delivered.

Under SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," a VPP is considered a sale of proved reserves. As a result, the Company (i) removed the proved reserves associated with the VPPs; (ii) recognized the VPP proceeds as deferred revenue which are being amortized on a unit-of-production basis to oil and gas revenues over the terms of the VPPs; (iii) retained responsibility for 100 percent of the production costs and capital costs related to VPP interests; and (iv) no longer recognizes production associated with the VPP volumes.

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The following table provides information about the deferred revenue carrying values of the Company's VPPs:

	Gas	Oil	Total
	(in thousands)		
Deferred revenue at December 31, 2006	$ 175,088	$ 489,423	$ 664,511
Less: 2007 amortization	(71,575)	(109,656)	(181,231)
Deferred revenue at December 31, 2007	$ 103,513	$ 379,767	$ 483,280

The above deferred revenue amounts will be recognized in oil and gas revenues in the Consolidated Statements of Operations as noted below, assuming the related VPP production volumes are delivered as scheduled (in thousands):

2008	$ 158,138
2009	147,906
2010	90,215
2011	44,951
2012	42,070
	$ 483,280

NOTE U. Insurance Claims

Fain Plant. During May 2005, the Company sustained damages as a result of a fire at its Fain gas plant in the West Panhandle field. The damages interrupted production from mid-May through mid-July of 2005. The Company maintained business interruption and physical damage insurance coverage for such circumstances. The Company recognized a total of $17.9 million in business interruption recoveries and $4.4 million in physical damage recoveries associated with the Fain gas plant fire. The Company recognized $14.2 million of the business interruption recoveries in 2005 and the remaining $3.7 million in 2006, which is included in other income in the accompanying Consolidated Statements of Operations.

Hurricanes Katrina and Rita. During August and September 2005, the Company sustained damages as a result of Hurricanes Katrina and Rita at various facilities in the Gulf of Mexico. Other than the East Cameron facility discussed further below, the damages to the facilities were covered by physical damage insurance.

The Company filed a business interruption claim with its insurance provider related to its Devils Tower field resulting from its inability to sell production as a result of damages to third-party facilities. During 2006, the Company settled its business interruption claim with its insurance provider for $18.5 million, which is included in income from discontinued operations in the accompanying Consolidated Statements of Operations.

As a result of Hurricane Rita, the Company's East Cameron facility, located in the Gulf of Mexico shelf, was destroyed. The Company currently estimates that it will cost approximately $185 million to reclaim and abandon the East Cameron facility. The operations to reclaim and abandon the East Cameron facilities began in January 2007. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis prepared by a third party engineering firm for a majority of the work, an estimate by the Company for the remaining work that was not covered by the third-party analysis and actual abandonment activity to date. During 2007, 2006 and 2005, the Company recorded additional abandonment obligation charges for changes in estimates of $66.0 million, $75.0 million and $39.8 million, respectively, which amounts are included in hurricane activity, net in the accompanying Consolidated Statements of Operations.

The $185 million estimate to reclaim and abandon the East Cameron facilities contains a number of assumptions that could cause the ultimate cost to be higher or lower as there are many uncertainties when working offshore and underwater with damaged equipment and wellbores. The Company currently believes costs could

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range from $185 million to $205 million; however, at this point no better estimate than any other amount within the range can be determined, thus the Company has recorded the estimated provision of $185 million.

The Company filed a claim with its insurance providers regarding the loss at East Cameron. Under the Company's insurance policies, the East Cameron facility had the following coverages: (a) $14 million of scheduled property value for the platform, (b) $4 million of scheduled business interruption insurance after a deductible waiting period, (c) $100 million of well restoration and safety, in total, for all assets per occurrence and (d) $400 million for debris removal coverage for all assets per occurrence.

In December 2005, the Company received the $14 million of scheduled property value for the East Cameron assets and recognized a gain of $9.7 million associated therewith. The Company received the $4 million of business interruption recoveries in 2006, which is reflected in interest and other income in the accompanying Consolidated Statements of Operations. During the fourth quarter of 2006, the Company recorded estimated insurance recoveries of $43 million, which is reflected in other current assets in the accompanying Consolidated Balance Sheet and in hurricane activity, net in the accompanying Consolidated Statements of Operations, related to the estimated costs for the debris removal portion of the claim as the Company believes that it is probable that it will be successful in asserting coverage under the debris removal part of its insurance coverage. During 2007, the Company received $5 million, reflected in hurricane activity, net in the Consolidated Statements of Operations, from one of its insurance providers related to debris removal. At the present, no recoveries have been reflected related to certain costs associated with plugging and abandonment and the well restoration and safety coverages, as the Company is working to resolve coverage issues regarding coverage under this section of the insurance policies. In the third quarter of 2007, the Company commenced legal actions against its insurance carriers regarding policy coverage issues, primarily related to debris removal, certain costs associated with plugging and abandonment, and the well restoration and safety coverages. However, the Company continues to expect that a substantial portion of the loss will be recoverable from insurance.

NOTE V. Discontinued Operations

During 2007, 2006 and 2005, the Company sold its interests in the following significant oil and gas assets:

Country	**Description of Assets**	**Date Divested**	**Net Proceeds (in millions)**		**Gain**
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005	$ 197.2		$ 138.3
United States	Two Gulf of Mexico shelf fields	August 2005	$ 59.2		$ 27.9
United States	Deepwater Gulf of Mexico fields	March 2006	$ 1,156.9	(a)	$ 725.3
Argentina	Argentine assets	April 2006	$ 669.6		$ 10.9
Canada	Canadian assets	November 2007	$ 525.7	(b)	$ 101.3

(a) Net proceeds do not reflect the cash payment of $164.3 million for terminated hedges associated with the deepwater Gulf of Mexico assets.

(b) In November 2007, the Company did not receive $132.8 million of the proceeds which was deposited in a Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications which were received in January 2008. See Note E for additional information regarding the Canadian escrow account.

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Pursuant to 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. The following table represents the components of the Company's discontinued operations for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Revenues and other income:			
Oil and gas	$ 135,842	$ 322,426	$ 920,704
Interest and other	1,885	33,550	70,590
Gain on disposition of assets, net (a)	100,178	731,827	166,521
	237,905	1,087,803	1,157,815
Costs and expenses:			
Oil and gas production	55,400	80,514	154,032
Depletion, depreciation and amortization (a)	34,502	82,770	311,472
Exploration and abandonments (a)	14,423	21,275	73,400
General and administrative	12,302	14,501	14,619
Accretion of discount on asset retirement obligations (a)	1,767	1,904	4,527
Interest	389	442	1,800
Other	6,345	1,382	32,088
	125,128	202,788	591,938
Income from discontinued operations before income taxes	112,777	885,015	565,877
Income tax benefit (provision):			
Current	(4,915)	(151,677)	(7,832)
Deferred (a)	22,887	(143,824)	(207,782)
Income from discontinued operations	$ 130,749	$ 589,514	$ 350,263

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(a) Represents the significant noncash components of discontinued operations included in the Company's Consolidated Statements of Cash Flows.

NOTE W. Pioneer Southwest Energy Partners L.P. Initial Public Offering (unaudited)

On January 8, 2008, Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest"), a subsidiary of the Company, filed an amendment to its registration statement (subject to completion) with the SEC to sell limited partner interests. If the offering is completed, Pioneer Southwest would own interests in certain oil and gas properties currently owned by the Company in the Spraberry field in the Permian Basin of West Texas. Pioneer Southwest's registration statement contemplates an offering of 7,500,000 common units representing a 35.3 percent limited partner interest in Pioneer Southwest. If the offering is completed, the Company would own a 0.1 percent general partner interest and a 64.6 percent limited partner interest in Pioneer Southwest. The underwriters would be granted a 30-day option to purchase up to 1,125,000 additional common units. The Company's limited partner interest would be reduced to 61.4 percent if the underwriters exercise their over-allotment option in full. In February 2008, the Company announced that the initial public offering of common units of Pioneer Southwest has been postponed due to market conditions and timing of the offering remains uncertain. There can be no assurance that Pioneer Southwest will complete the offering, or if completed, that the offering will be structured as described above.

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Capitalized Costs

	December 31, 2007	2006
	(in thousands)	
Oil and gas properties:		
Proved	$ 8,973,634	$ 7,967,708
Unproved	277,479	210,344
Capitalized costs for oil and gas properties	9,251,113	8,178,052
Less accumulated depletion, depreciation and amortization	(2,028,472)	(1,895,408)
Net capitalized costs for oil and gas properties	$ 7,222,641	$ 6,282,644

Costs Incurred for Oil and Gas Producing Activities (a)

	Property Acquisition Costs Proved	Unproved	Exploration Costs	Development Costs	Total Costs Incurred
	(in thousands)				
Year Ended December 31, 2007:					
United States	$ 331,526	$ 200,767	$ 335,778	$ 1,058,259	$ 1,926,330
Canada	82	3,620	32,160	64,584	100,446
South Africa	—	—	276	111,178	111,454
Tunisia	—	718	104,585	9,785	115,088
Other (b)	—	—	23,905	—	23,905
Total	$ 331,608	$ 205,105	$ 496,704	$ 1,243,806	$ 2,277,223
Year Ended December 31, 2006:					
United States	$ 78,318	$ 109,321	$ 296,301	$ 700,340	$ 1,184,280
Argentina	—	2	10,223	25,542	35,767
Canada	—	19,932	103,245	105,487	228,664
South Africa	—	—	288	131,475	131,763
Tunisia	—	5,000	40,813	336	46,149
Other (b)	—	10,584	36,172	—	46,756
Total	$ 78,318	$ 144,839	$ 487,042	$ 963,180	$ 1,673,379
Year Ended December 31, 2005:					
United States	$ 170,827	$ 60,731	$ 217,723	$ 454,109	$ 903,390
Argentina	—	512	36,878	92,250	129,640
Canada	2,593	7,344	43,437	77,863	131,237
South Africa	—	259	755	17,527	18,541
Tunisia	—	—	18,395	2,922	21,317
Other (b)	—	30,664	44,456	291	75,411
Total	$ 173,420	$ 99,510	$ 361,644	$ 644,962	$ 1,279,536

(a) The costs incurred for oil and gas producing activities includes the following amounts of asset retirement obligations:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in thousands)		
Proved property acquisition costs	$ 4,750	$ 981	$ 3,183
Exploration costs	1,499	3,376	—
Development costs	26,880	41,110	16,055
Total	$ 33,129	$ 45,467	$ 19,238

(b) Other is primarily comprised of activities in Nigeria and Equatorial Guinea.

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Results of Operations

Information about the Company's results of operations for oil and gas producing activities by geographic operating segment is presented in Note R of the accompanying Notes to Consolidated Financial Statements.

Reserve Quantity Information

The estimates of the Company's proved reserves as of December 31, 2007, 2006 and 2005, which were located in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The Company reports all 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 for production sharing arrangements reported under the "economic interest" method are subject to fluctuations in the commodity prices of 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. The reserve estimates as of December 31, 2007, 2006 and 2005 utilized respective oil prices of $95.45, $60.54 and $59.62 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $56.13, $29.82 and $36.34 per Bbl, and respective gas prices of $6.12, $5.13 and $6.36 per Mcf (reflecting adjustments for Btu content, gas processing and shrinkage).

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a rollforward of total proved reserves by geographic area and in total for the years ended December 31, 2007, 2006 and 2005, as well as proved developed reserves by geographic area and in total as of the beginning and end of each respective year. Oil and NGL volumes are expressed in MBbls, gas volumes are expressed in MMcf and total volumes are expressed in thousands of barrels of oil equivalent ("MBOE").

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	Year Ended December 31,								
	2007			2006			2005		
	Oil & NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)	Oil & NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)	Oil & NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)
Total Proved Reserves:									
UNITED STATES									
Balance, January 1	406,725	2,685,961	854,385	385,771	2,750,856	844,247	363,257	3,000,335	863,313
Revisions of previous estimates	15,571	35,542	21,495	(7,467)	(10,664)	(9,244)	(5,471)	(141,473)	(29,049)
Purchases of minerals-in-place	19,678	184,478	50,424	41,825	52,308	50,543	65,800	83,179	79,663
Extensions and discoveries	22,692	131,277	44,571	11,948	136,712	34,733	225	103,616	17,494
Production (b)	(13,575)	(132,840)	(35,715)	(14,091)	(134,445)	(36,499)	(16,311)	(197,391)	(49,210)
Sales of minerals-in-place	—	(1,363)	(227)	(11,261)	(108,806)	(29,395)	(21,729)	(97,410)	(37,964)
Balance, December 31	451,091	2,903,055	934,933	406,725	2,685,961	854,385	385,771	2,750,856	844,247
ARGENTINA									
Balance, January 1	—	—	—	34,024	404,323	101,411	33,168	560,374	126,564
Revisions of previous estimates	—	—	—	(306)	(2,043)	(646)	2,060	(137,640)	(20,881)
Extensions and discoveries	—	—	—	135	4,576	898	2,334	31,606	7,602
Production (b)	—	—	—	(1,072)	(16,025)	(3,743)	(3,538)	(50,017)	(11,874)
Sales of minerals-in-place	—	—	—	(32,781)	(390,831)	(97,920)	—	—	—
Balance, December 31	—	—	—	—	—	—	34,024	404,323	101,411
CANADA									
Balance, January 1	2,199	173,509	31,117	2,423	130,514	24,175	4,095	119,869	24,073
Revisions of previous estimates	(81)	(18,778)	(3,210)	(159)	(7,953)	(1,485)	434	15,887	3,082
Purchases of minerals-in-place	—	—	—	—	—	—	—	292	49
Extensions and discoveries	378	62,263	10,755	217	66,801	11,351	652	55,130	9,840
Production (b)	(234)	(16,295)	(2,950)	(282)	(15,853)	(2,924)	(311)	(15,665)	(2,922)
Sales of minerals-in-place	(2,262)	(200,699)	(35,712)	—	—	—	(2,447)	(44,999)	(9,947)
Balance, December 31	—	—	—	2,199	173,509	31,117	2,423	130,514	24,175
SOUTH AFRICA									
Balance, January 1	3,070	60,511	13,156	3,055	60,395	13,121	3,419	—	3,419
Revisions of previous estimates	(1,334)	(18,909)	(4,485)	1,521	116	1,541	694	—	694

Extensions and discoveries	—	—	—	—	—	—	1,347	60,395	11,413
Production (b)	(979)	(1,037)	(1,151)	(1,506)	—	(1,506)	(2,405)	—	(2,405)
Balance, December 31	757	40,565	7,520	3,070	60,511	13,156	3,055	60,395	13,121
TUNISIA									
Balance, January 1	4,977	7,846	6,284	3,769	—	3,769	4,852	—	4,852
Revisions of previous estimates	1,570	13,861	3,880	1,579	59	1,588	(510)	—	(510)
Extensions and discoveries	24,477	4	24,478	500	8,223	1,870	696	—	696
Production (b)	(1,403)	(917)	(1,557)	(871)	(436)	(943)	(1,269)	—	(1,269)
Sales of minerals-in-place	(11,771)	—	(11,771)	—	—	—	—	—	—
Balance, December 31	17,850	20,794	21,314	4,977	7,846	6,284	3,769	—	3,769
TOTAL									
Balance, January 1	416,971	2,927,827	904,942	429,042	3,346,088	986,723	408,791	3,680,578	1,022,221
Revisions of previous estimates	15,726	11,716	17,680	(4,832)	(20,485)	(8,246)	(2,793)	(263,226)	(46,664)
Purchases of minerals-in-place	19,678	184,478	50,424	41,825	52,308	50,543	65,800	83,471	79,712
Extensions and discoveries	47,547	193,544	79,804	12,800	216,312	48,852	5,254	250,747	47,045
Production (b)	(16,191)	(151,089)	(41,373)	(17,822)	(166,759)	(45,615)	(23,834)	(263,073)	(67,680)
Sales of minerals-in-place	(14,033)	(202,062)	(47,710)	(44,042)	(499,637)	(127,315)	(24,176)	(142,409)	(47,911)
Balance, December 31	469,698	2,964,414	963,767	416,971	2,927,827	904,942	429,042	3,346,088	986,723

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(a) The proved gas reserves as of December 31, 2007, 2006 and 2005 include 290,599 MMcf, 316,528 MMcf and 306,303 MMcf, respectively, of gas that will be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.

(b) Production for 2007, 2006 and 2005 includes approximately 17,347 MMcf, 17,364 MMcf, and 14,452 MMcf of field fuel, respectively. Also, for 2007, 2006 and 2005, production includes 2,950 MBOE, 9,735 MBOE and 31,195 MBOE of production associated with discontinued operations. See Note V for additional information.

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	Year Ended December 31,								
	2007			**2006**			**2005**		
	Oil & NGLs (MBbls)	**Gas (MMcf)(a)**	**Total (MBOE)**	**Oil & NGLs (MBbls)**	**Gas (MMcf)(a)**	**Total (MBOE)**	**Oil & NGLs (MBbls)**	**Gas (MMcf)(a)**	**Total (MBOE)**
Proved Developed Reserves:									
United States	211,814	1,805,974	512,809	210,680	1,875,866	523,324	223,749	2,045,275	564,628
Argentina	—	—	—	20,844	282,815	67,980	20,565	320,616	74,001
Canada	2,053	117,672	21,665	2,202	99,025	18,706	3,849	107,547	21,773
South Africa	1,822	—	1,822	1,708	—	1,708	3,419	—	3,419
Tunisia	4,977	7,846	6,285	3,769	—	3,769	4,852	—	4,852
Balance, January 1	220,666	1,931,492	542,581	239,203	2,257,706	615,487	256,434	2,473,438	668,673
United States	238,072	1,976,080	567,419	211,814	1,805,974	512,809	210,680	1,875,866	523,324
Argentina	—	—	—	—	—	—	20,844	282,815	67,980
Canada	—	—	—	2,053	117,672	21,665	2,202	99,025	18,706
South Africa	757	40,565	7,518	1,822	—	1,822	1,708	—	1,708
Tunisia	17,850	20,794	21,316	4,977	7,846	6,285	3,769	—	3,769
Balance, December 31	256,679	2,037,439	596,253	220,666	1,931,492	542,581	239,203	2,257,706	615,487

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end commodity prices (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2007, commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge obligations, less associated estimated income taxes and discounted at ten percent, was a liability of approximately $139.1 million at December 31, 2007.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable reserves, anticipated future commodity prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

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The following tables provide the standardized measure of discounted future cash flows by geographic area and in total as of December 31, 2007, 2006 and 2005, as well as a roll forward in total for each respective year:

	December 31, 2007	2006	2005
	(in thousands)		
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 52,649,378	$ 32,162,975	$ 37,171,750
Future production costs	(14,562,540)	(10,605,170)	(10,911,204)
Future development costs	(4,252,134)	(3,746,920)	(2,757,072)
Future income tax expense	(11,265,645)	(5,695,788)	(7,552,644)
	22,569,059	12,115,097	15,950,830
10% annual discount factor	(14,303,502)	(7,925,926)	(9,872,066)
Standardized measure of discounted future cash flows	$ 8,265,557	$ 4,189,171	$ 6,078,764
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ —	$ —	$ 2,256,468
Future production costs	—	—	(366,362)
Future development costs	—	—	(353,182)
Future income tax expense	—	—	(282,661)
	—	—	1,254,263
10% annual discount factor	—	—	(446,366)
Standardized measure of discounted future cash flows	$ —	$ —	$ 807,897
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ —	$ 1,054,264	$ 1,062,258
Future production costs	—	(399,248)	(404,891)
Future development costs	—	(115,721)	(46,312)
Future income tax expense	—	(69,693)	(166,333)
	—	469,602	444,722
10% annual discount factor	—	(200,313)	(190,655)
Standardized measure of discounted future cash flows	$ —	$ 269,289	$ 254,067
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 365,145	$ 509,081	$ 503,499
Future production costs	(36,934)	(82,989)	(56,987)
Future development costs	(44,263)	(165,318)	(248,005)
Future income tax expense	(31,584)	(58,870)	(18,510)
	252,364	201,904	179,997
10% annual discount factor	(37,108)	(58,182)	(70,453)

Standardized measure of discounted future cash flows	$ 215,256	$ 143,722	$ 109,544

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	December 31, 2007	2006	2005
	(in thousands)		
TUNISIA			
Oil and gas producing activities:			
Future cash inflows	$ 1,892,519	$ 329,773	$ 214,982
Future production costs	(165,668)	(47,116)	(9,164)
Future development costs	(45,831)	(16,265)	(2,700)
Future income tax expense	(860,342)	(148,361)	(121,675)
	820,678	118,031	81,443
10% annual discount factor	(284,607)	(31,224)	(34,818)
Standardized measure of discounted future cash flows	$ 536,071	$ 86,807	$ 46,625
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 54,907,042	$ 34,056,093	$ 41,208,957
Future production costs	(14,765,142)	(11,134,523)	(11,748,608)
Future development costs(a)	(4,342,228)	(4,044,224)	(3,407,271)
Future income tax expense	(12,157,571)	(5,972,712)	(8,141,823)
	23,642,101	12,904,634	17,911,255
10% annual discount factor	(14,625,217)	(8,215,645)	(10,614,358)
Standardized measure of discounted future cash flows	$ 9,016,884	$ 4,688,989	$ 7,296,897

(a) Includes $471.5 million, $324.1 million and $357.5 million of undiscounted future asset retirement expenditures estimated as of December 31, 2007, 2006 and 2005, respectively, using current estimates of future abandonment costs. See Note L for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Oil and gas sales, net of production costs	$ (1,462,189)	$ (1,516,503)	$ (2,227,267)
Net changes in prices and production costs	4,700,608	(1,921,270)	3,932,683

Extensions and discoveries	1,889,282	413,200	459,251
Development costs incurred during the period	661,956	672,572	446,978
Sales of minerals-in-place	(970,215)	(1,926,423)	(1,492,864)
Purchases of minerals-in-place	585,924	280,475	645,315
Revisions of estimated future development costs	(897,587)	(1,041,343)	(907,229)
Revisions of previous quantity estimates	322,470	(38,837)	(595,873)
Accretion of discount	660,755	895,455	908,047
Changes in production rates, timing and other	1,240,959	486,328	78,880
Change in present value of future net revenues	6,731,963	(3,696,346)	1,247,921
Net change in present value of future income taxes	(2,404,068)	1,088,438	(594,099)
	4,327,895	(2,607,908)	653,822
Balance, beginning of year	4,688,989	7,296,897	6,643,075
Balance, end of year	$ 9,016,884	$ 4,688,989	$ 7,296,897

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Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2007 and 2006:

	Quarter			
	First	Second	Third	Fourth
	(in thousands, except per share data)			
Year ended December 31, 2007:				
Oil and gas revenues:				