UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2002

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 1400, 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 whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES X NO

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
YES X NO ___

Aggregate market value of the voting common equity held by non-affiliates of the Registrant 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	$3,011,384,455
Number of shares of Common Stock outstanding as of February 17, 2003	117,299,334

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held May 15, 2003 - Referenced in Part III of this report.

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Parts I and II of this annual report on Form 10-K (the "Report") contain forward looking statements that involve risks and uncertainties. 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 Regulation" and "Item 1. Business - Risks Associated with Business Activities" for a description of various factors that could materially affect the ability of Pioneer Natural Resources Company to achieve the anticipated results described in the forward looking statements.

Definitions of Oil and Gas Terms and Conventions Used Herein

Within this Report, the following oil and gas 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; "Btu" means British thermal unit and is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit; "LIBOR" means London Interbank Offered Rate, which is a market rate of interest; "MMBtu" means one million Btu's; "MBbl" means one thousand Bbls; "MBOE" means one thousand BOE; "MMBOE" means one million BOE; "Mcf" means one thousand cubic feet and is a measure of natural gas volume; "MMcf" means one million cubic feet; "NGL" means natural gas liquid; "NYMEX" means The New York Mercantile Exchange; "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.

"Standardized Measure" means the after-tax present value of estimated future net revenues of proved reserves, determined in accordance with the rules and regulations of the United States Securities and Exchange Commission (the "SEC"), using prices and costs in effect at the specified date and a 10 percent discount rate; "acquisition and finding cost per BOE" means total costs incurred divided by the summation of proved reserves attributable to revisions of previous estimates, purchases of minerals in place and new discoveries and extensions; and "reserve replacement percentage" means, expressed as a percentage, the summation of annual proved reserves, on a BOE basis, attributable to revisions of previous estimates, purchases of minerals in place and new discoveries and extensions divided by annual production of oil, NGLs and gas, on a BOE 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 NGL.

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 Pioneer Natural Resources 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; and, all currency amounts are expressed in U.S. dollars.

PART I

ITEM 1. BUSINESS

General

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. Pioneer is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, Argentina, Canada, Gabon, South Africa and Tunisia.

The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 1400, Irving, Texas 75039. The Company's telephone number is (972) 444-9001. The Company maintains other offices in Midland, Texas; Buenos Aires, Argentina; Calgary, Canada; Capetown, South Africa; and Tunis, Tunisia. At December 31, 2002, the Company had 979 employees, 491 of whom were employed in field and plant operations.

Available Information

Pioneer files annual, quarterly, and current reports, proxy statements, and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, DC 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 on or through its Internet website (http://www.pioneernrc.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 provide shareholders with superior 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. Historically, these strategies have been anchored by the Company's long-lived Spraberry oil field and Hugoton and West Panhandle gas fields' reserves and production. Underlying these fields are approximately 65 percent of the Company's proved oil and gas reserves which have a remaining productive life in excess of 40 years. The stable base of oil and gas production from these fields, combined with: (i) production from the Company's Canyon Express gas project which began production in September 2002; (ii) the initial production from the Company's Falcon gas discovery in the deepwater Gulf of Mexico and the Sable oil discovery in South Africa expected during the second quarter of 2003; and (iii) initial production from the Company's Devils Tower oil discovery in the deepwater Gulf of Mexico expected during the first quarter of 2004, will generate the operating cash flows that will provide Pioneer with continued financial flexibility. These exploration successes represent the results of the Company's ability to selectively reinvest capital from the long-lived Spraberry, Hugoton and West Panhandle fields to areas offering superior investment returns. Similarly, the Company will continue to: (a) selectively explore for and develop proved reserve discoveries in areas that offer superior reserve growth and profitability potential; (b) invest in the personnel and technology necessary to maximize the Company's exploration and development successes; and (c) enhance liquidity, allowing the Company to take advantage of future exploration, development and acquisition opportunities. The Company is committed to continuing to enhance shareholder investment returns through adherence to these strategies.

Business Activities

The Company is an independent oil and gas exploration and development company. Pioneer's purpose is to competitively and profitably explore for, develop and produce oil, NGL and gas reserves. In so doing, the Company sells homogenous oil, NGL and gas units which, except for geographic and relatively minor qualitative differentials, 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 through superior capital investment decisions, technological innovation and price and cost management.

Petroleum industry. The petroleum industry has been characterized by fluctuating oil, NGL and gas commodity prices and relatively stable supplier costs during the three years ended December 31, 2002. During and just prior to 2000, the Organization of Petroleum Exporting Countries ("OPEC") and certain other oil exporting nations reduced their oil export volumes. Those reductions in oil export volumes had a positive impact on world oil prices, as did overall gas supply and demand fundamentals on North American gas prices. During 2001, world oil and North American gas supply and demand fundamentals shifted, primarily as a result of an economic recession curtailing demand, causing reductions in world oil and North American gas prices. During 2002, world oil prices increased in response to political unrest and supply disruptions in the Middle East and Venezuela. During the third and fourth quarters of 2002, North American gas prices improved as market fundamentals strengthened. The Company's outlook for 2003 commodity prices is uncertain. Significant factors that will impact 2003 commodity prices include the final resolution of issues currently impacting Iraq and Venezuela; the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals. To mitigate the impact of volatile commodity prices on the Company's net asset value, Pioneer periodically enters into commodity hedge contracts. See 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 2002, 2001 and 2000 from the Company's hedging activities and the Company's open hedge positions at December 31, 2002.

The Company. The Company's asset base is anchored by the Spraberry oil field located in West Texas, 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 Alaska, the United States Gulf of Mexico and onshore Gulf Coast areas, and internationally in Argentina, Canada, Gabon, 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 between long-lived, dependable production and exploration and development 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 and management support to United States and foreign subsidiaries that explore for, develop and produce oil, NGL and gas reserves. Production operations are principally located domestically in Texas, Kansas, Louisiana and the Gulf of Mexico, and internationally in Argentina and Canada.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGL and gas through development drilling, production enhancement activities and acquisitions of producing properties while minimizing the controllable costs associated with the production activities. During 2002, the Company's average daily oil, NGL and gas production decreased primarily due to normal production declines, reduced Argentine demand for gas, the Company's curtailment of Argentine drilling activities during the first half of 2002 and the December 2001 sale of the Company's Rycroft/Spirit River field in Canada. During 2001 and 2000, the Company's average daily oil, NGL and gas production decreased primarily as a result of oil and gas property divestitures that were supportive of the Company's debt reduction goal. Production, price and cost information with respect to the Company's properties for each of 2002, 2001 and 2000 is set forth under "Item 2. Properties - Selected Oil and Gas Information - Production, Price and Cost Data".

Drilling activities. The Company seeks to increase its oil and gas reserves, production and cash flow through exploratory and development drilling and by conducting other production enhancement activities, such as well recompletions. During the five years ended December 31, 2002, the Company drilled 1,810 gross (1,279.7 net) wells, 88.5 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's

interest) of $1.6 billion. During 2002, the Company drilled 229 gross (153.2 net) wells. Drilling and facility costs (net to the Company's interest) totaled $439.3 million during 2002, 79 percent of which was spent on development activities including $221.6 million towards completing the Canyon Express, Falcon and Devils Tower deepwater Gulf of Mexico projects and the Sable project offshore South Africa. The Company's current 2003 capital expenditure budget is expected to range from $450 million to $550 million. Excluding the 2002 Falcon field and West Panhandle field acquisitions, the Company's 2003 capital expenditure budget is comparable to 2002 costs incurred for oil and gas producing activities. Development expenditures to complete the Falcon, Devils Tower and Sable projects will decline to approximately $35 million during 2003, while aggressive development drilling programs in the Company's core Spraberry oil field, Hugoton and West Panhandle gas fields, the United States Gulf Coast, Argentina and Canada will resume with approximately twice as many wells anticipated in 2003 versus 2002. The Company has allocated the budgeted 2003 capital expenditures as follows: 65 percent to development drilling and facility activities and 35 percent to exploration activities.

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, 2002 include proved undeveloped reserves and proved developed reserves that are behind pipe of 154.2 million Bbls of oil and NGLs and 647.7 Bcf of gas. Development of those 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 undeveloped prospects provides attractive development and exploration opportunities for at least the next three to five years.

Exploratory activities. Since 1998, the Company has devoted significant efforts and resources on hiring and developing a highly skilled exploration staff as well as acquiring and drilling a portfolio of exploration opportunities. The Company's commitment to exploration has resulted in significant discoveries during this time period, such as the 1998 Sable oil field discovery in South Africa; the 1999 Aconcagua, 2000 Devils Tower, 2001 Falcon and 2003 Harrier discoveries in the deepwater Gulf of Mexico; the 2001 Olowi permit discovery located in the Southern Gabon basin; and the 2002 Borj El Khadra permit discovery in the Ghadames basin onshore Southern Tunisia. The Company currently anticipates that its 2003 exploration efforts will be approximately 35 percent of total 2003 expenditures and will be concentrated domestically in Alaska and the Gulf of Mexico, and internationally in Gabon, South Africa and Tunisia. Exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities. See "Item 1. Business - Risks Associated with Business Activities - Drilling activities" below.

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying non-core 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 financial flexibility through reduced debt levels.

During 2002, 2001 and 2000, the Company's divestitures consisted of the early termination of derivative hedge contracts and the sales of oil and gas properties and other assets for net proceeds of $118.9 million, $113.5 million and $102.7 million, respectively, which resulted in 2002, 2001 and 2000 net divestiture gains of $4.4 million, $7.7 million and $34.2 million, respectively. The Company's 2002 net proceeds from asset divestitures were primarily derived from the early termination of interest rate and commodity hedges and the sale of certain gas properties in Oklahoma. The Company's 2001 divestitures were primarily derived from the early termination of interest rate and commodity hedges, the sale of the Company's remaining investment in the common stock of a non-affiliated entity and the sale of certain oil properties in Canada. The assets that the Company divested during 2000 were primarily comprised of an investment in a non-affiliated entity and non-strategic United States oil and gas properties located in Oklahoma, New Mexico and Louisiana. The net cash proceeds from the 2002, 2001 and 2000 asset dispositions were primarily used to fund additions to oil and gas properties or to reduce the Company's outstanding indebtedness. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures.

The Company anticipates that it will continue to sell non-strategic 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.

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 2002, the Company expended $195.5 million of acquisition capital to purchase additional interests in, and other assets associated with, its Falcon field development project in the deepwater Gulf of Mexico and its West Panhandle gas field and unproved property interests in the Gulf of Mexico, the Alaskan North Slope, the Borj El Khadra permit in Tunisia and other areas. The Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest and operates the Falcon field development and related exploration blocks.

The Company also completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded a $100.4 million increase to proved oil and gas properties, a $3.8 million increase to unproved oil and gas properties and $1.9 million of assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash.

During 2001, the Company expended $170.8 million of capital to acquire proved and unproved oil and gas properties. Excluding cash and other working capital acquired, the Company paid $92.9 million, through the issuance of common stock, to complete the agreement and plan of merger among Pioneer, Pioneer Natural Resources USA, Inc. and 42 affiliated limited partnerships. Additionally, $77.9 million was spent during 2001 to acquire additional working interests in the deepwater Gulf of Mexico Aconcagua discovery, the related Canyon Express gathering system and the Devils Tower project; 21 deepwater Gulf of Mexico blocks; 250,000 acres in the Anticlinal Campamento, Dos Hermanas and La Calera areas of the Neuquen Basin in Argentina; and a 30 percent interest in the Anaguid permit in the Ghadames basin onshore Southern Tunisia.

During 2000, the Company expended $67.2 million to acquire proved and unproved oil and gas properties. Strategic acquisitions of proved properties during 2000 included incremental working interests in the deepwater Gulf of Mexico discovery at Devils Tower and the Company's Canadian Chinchaga gas field. The Company also acquired an interest in the Camden Hills deepwater Gulf of Mexico discovery and the related Canyon Express gathering system during 2000.

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 acquisitions.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas properties or related assets; entities owning oil and gas properties or related 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.

Operations by Geographic Area

The Company operates in one industry segment. During 2002, 2001 and 2000, the Company had oil and gas producing activities in the United States, Argentina and Canada, and had exploration and/or development activities in the United States Gulf Coast area, the Gulf of Mexico, Argentina, Canada, Gabon, South Africa and Tunisia. See Note P 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 spot price for gas or the posted price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply conditions.

Significant purchasers. During 2002, the Company's primary purchasers of oil were ExxonMobil Corporation ("ExxonMobil") and Plains Marketing LP ("Plains"), the Company's primary purchaser of NGLs was Williams Energy Services ("Williams") and the Company's primary purchaser of gas was Anadarko Petroleum Corporation ("Anadarko"). Approximately seven percent of the Company's 2002 combined oil, NGL and gas revenues were attributable to sales to each of ExxonMobil, Plains, Williams and Anadarko. 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 periodically enters into commodity derivative contracts (swaps and collars) in order to (i) reduce the effect of the volatility of price changes on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) lock in prices to protect the economics related to 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 to oil and gas revenues during 2002, 2001 and 2000 from the Company's commodity hedging activities and the Company's open commodity hedge positions at December 31, 2002.

Competition, Markets and Regulation

Competition. The oil and gas industry is highly competitive. A large number of 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 return on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, investigate and purchase such properties and the financial resources necessary to acquire and develop them. 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 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 oil and gas prices or the degree to which oil and gas prices will be affected, the prices for any oil or gas that the Company produces will generally approximate current market prices in the geographic region.

Governmental regulation. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the United States Securities and Exchange Commission. 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 and its consolidated subsidiaries is made known to the Company's management and that the financial statements and other financial information included in this Report do not contain any untrue statement of a material fact, or omit to state a material fact, necessary to make the statements made in this Report not misleading.

Oil and gas exploration and production operations are also subject to various types of regulation by local, state, federal and foreign agencies. Additionally, the Company's operations are subject to state conservation laws and regulations, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of wells. States and foreign governments generally impose a production or severance tax with respect to production and sale of oil and gas within their respective jurisdictions. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Additional proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the Federal Energy Regulatory Commission, state regulatory bodies, the courts and foreign governments. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on the Company's operations.

Environmental and health controls. The Company's operations are subject to numerous federal, state, local and foreign laws and regulations relating to environmental and health protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and impose substantial liabilities for pollution resulting from oil and gas operations. These laws and regulations may also restrict air emissions or other discharges resulting from the operation of natural gas processing plants, pipeline systems and other facilities that the Company owns. Although the Company believes that compliance with environmental laws and regulations will not have a material adverse effect on its results of operations or financial condition, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities, including potential criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations or claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and 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 generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The United States Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases, and has in the past owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although the Company has used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial plugging operations to prevent future contamination.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Prevention Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act ("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and

certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial liability for the costs of removing a spill. OPA requires responsible parties to establish and maintain evidence of financial responsibility to cover removal costs and damages resulting from an oil spill. OPA calls for a financial responsibility of $35 million to cover pollution cleanup for offshore facilities. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. The Company does not believe that the OPA, CWA or related state laws are any more burdensome to it than they are to other similarly situated oil and gas companies.

Many states in which the Company operates have recently begun to regulate naturally occurring radioactive materials ("NORM") and NORM wastes that are generated in connection with oil and gas exploration and production activities. NORM wastes typically consist of very low-level radioactive substances that become concentrated in pipe scale and in production equipment. State regulations may require the testing of pipes and production equipment for the presence of NORM, the licensing of NORM-contaminated facilities and the careful handling and disposal of NORM wastes. The Company believes that the growing regulation of NORM will have a minimal effect on the Company's operations because the Company generates only a very small quantity of NORM on an annual basis.

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 environmental laws will not, in the future, result in a curtailment of production or processing or a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's results of operations and financial condition.

The Company employs an environmental manager and environmental specialists charged with monitoring environmental and regulatory compliance. The Company performs an environmental review as part of the due diligence work on potential acquisitions, including acquisitions of oil and gas properties. The Company is not aware of any material environmental legal proceedings pending against it or any material environmental liabilities to which it may be subject.

Risks Associated with Business Activities

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.

Commodity prices. The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on prices of oil and gas, which are affected by numerous factors beyond the Company's control. Oil and gas prices historically have been very volatile. A significant downward trend in commodity prices would have a material adverse effect on the Company's revenues, profitability and cash flow and could, under certain circumstances, result in a reduction in the carrying value of the Company's oil and gas properties and an increase in the Company's deferred tax asset valuation allowance.

Drilling activities. 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 and shortages or delays in the delivery of 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 or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of the Company's capital budget devoted to higher risk exploratory projects, it is likely that the Company will continue to experience exploration and abandonment expense.

Unproved properties. At December 31, 2002 and 2001, the Company carried unproved property costs of $219.1 million and $187.8 million, respectively. United States generally accepted accounting principles require periodic evaluation of these costs on a project-by-project basis in comparison to their estimated 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.

Acquisitions. Acquisitions of producing oil and gas properties have been a key 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 properties on a profitable basis. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. 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.

Divestitures. The Company regularly reviews its property base for the purpose of identifying non-strategic 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 non-strategic assets, including the availability of purchasers willing to purchase the non-strategic assets at prices acceptable to the Company.

Operation of natural gas processing plants. As of December 31, 2002, the Company owns interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. There are significant risks associated with the operation of natural gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a natural 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.

Operating hazards and uninsured losses. 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 pollution and other environmental damage, any of which 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 these risks, either because such insurance is not available or because of the high premium costs associated with obtaining such insurance.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of toxic substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of federal, state and 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 penalties, damages or other liabilities, and compliance 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 Regulation - Environmental and health controls".

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 future environmental laws will not result in a curtailment of production or processing or a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Debt restrictions and availability. The Company is a borrower under fixed term senior notes and a corporate credit facility. The terms of the Company's borrowings under the senior notes and the corporate 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, interest rates and competition for available debt financing. See Note E of Notes to Consolidated Financial Statements included in "Item 8.

Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt and the terms associated therewith.

Competition. The oil and gas industry is highly competitive. The Company competes with other companies, producers and operators for acquisitions and in the exploration, development, production and marketing of oil and gas. Some of these competitors have substantially greater financial and other resources than the Company. See "Item 1. Business - Competition, Markets and Regulation".

Government regulation. 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 Regulation".

International operations. At December 31, 2002, approximately 20 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (16 percent in Argentina, three percent in Canada and one percent in South Africa). The success and profitability of international operations may be adversely affected by risks associated with international activities, including economic and labor conditions, political instability, tax laws (including host-country export, excise and income taxes and United States taxes on foreign subsidiaries) and changes in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be denominated. To the extent that the Company is involved in international activities, changes in exchange rates can adversely affect the Company's future consolidated financial position, results of operations and liquidity. See Critical Accounting Estimates included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information specific to Argentina's economic and political situation.

Estimates of reserves and future net revenues. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues therefrom. The estimates of proved reserves and related future net revenues set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate. Therefore, such estimates should not be construed as accurate estimates of the current market value of the Company's proved reserves.

ITEM 2. PROPERTIES

The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2002 was based on reserve reports audited by Netherland, Sewell & Associates, Inc. for the Company's major properties in Canada, South Africa and the United States, reserve reports audited by Gaffney, Cline & Associates, Inc. for the Company's properties located in the Neuquen Basin in Argentina, and reserve reports prepared by the Company's engineers for all other properties. The reserve audits conducted by Netherland, Sewell & Associates, Inc. and Gaffney, Cline & Associates, Inc., in aggregate, represented 71 percent of the Company's estimated proved quantities of reserves as of December 31, 2002. The information in this Report about the Company's oil, NGL and gas reserves as of December 31, 2001 and 2000 was based on proved reserves as determined by the Company's engineers.

Numerous uncertainties exist in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. This Report contains estimates of the Company's proved oil and gas reserves and the related future net revenues, which are based on various assumptions, including those prescribed by the SEC. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses, geologic success and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities and related Standardized Measure of proved reserves set forth in this Report. In addition, the Company's reserves may be subject to downward or upward revisions based on production performance, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors. Therefore, estimates of the Standardized Measure of proved reserves should not be construed as accurate estimates of the current market value of the Company's proved reserves.

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 oil and gas spot prices 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 because of seasonal price fluctuations or other varying market conditions. Standardized Measures as of any

date are not necessarily indicative of future results of operations. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received.

The Company did not provide estimates of total proved oil and gas reserves during 2002, 2001 or 2000 to any federal authority or agency, other than the SEC.

Proved Reserves

The Company's proved reserves totaled 736.7 million BOE at December 31, 2002, 671.4 million BOE at December 31, 2001 and 628.2 million BOE at December 31, 2000, representing $4.1 billion, $2.5 billion and $5.6 billion, respectively, of Standardized Measure or $5.1 billion, $2.5 billion and $7.0 billion, respectively, on a pre-tax basis. The ten percent increase in reserve volumes and 65 percent increase in Standardized Measure during 2002 were attributable to an increase in commodity prices, the purchase of incremental interests in two core assets and the Company's successful capital investments. The seven percent increase in proved reserve volumes during 2001 was primarily attributable to the Company's successful capital investments, while the 56 percent decrease in Standardized Measure during 2001 was primarily due to decreases in commodity prices.

On a BOE basis, 67 percent of the Company's total proved reserves at

December 31, 2002 were proved developed reserves. Based on reserve information as of December 31, 2002, and using the Company's production information for 2002, the reserve-to-production ratio associated with the Company's proved reserves was 18 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily production by geographic area as of and for the year ended December 31, 2002:

PROVED OIL AND GAS RESERVES AND AVERAGE DAILY PRODUCTION

	Proved Reserves as of December 31, 2002				2002 Average Daily Production (a)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (000)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States.........	337,631	1,483,971	584,960	$ 3,456,691	43,949	232,360	82,677
Argentina............	31,532	532,081	120,211	340,106	8,680	78,220	21,716
Canada...............	2,361	119,328	22,249	199,012	1,070	48,365	9,131
South Africa..........	8,475	-	8,475	121,363	-	-	-
Tunisia..............	845	-	845	9,380	-	-	-
Total................	380,844	2,135,380	736,740	$ 4,126,552	53,699	358,945	113,524

<FN>

(a) The 2002 average daily production was calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

</FN>

Finding Cost and Reserve Replacement

The Company's acquisition and finding costs per BOE for 2002, 2001 and 2000 were $6.30, $7.49 and $4.66 per BOE, respectively. The average acquisition and finding cost for the three-year period from 2000 to 2002 was $6.24 per BOE, representing a 32 percent increase over the 2001 three-year average rate of $4.74 per BOE. This increase was largely attributable to the $221.6 million of development capital that the Company spent during 2002 to develop its Canyon Express, Falcon and Devils Tower development projects in the deepwater Gulf of Mexico and its Sable development project offshore South Africa.

During 2002, the Company replaced 258 percent of its annual production on a BOE basis (384 percent for oil and NGLs and 144 percent for gas). During 2001, the Company replaced 208 percent of its annual production on a BOE basis (169 percent for oil and NGLs and 245 percent for gas). During 2000, the Company replaced 167 percent of its annual production on a BOE basis (196 percent for oil and NGLs and 140 percent for gas). The Company's 2002 reserve replacement percentage was the result of revisions of previous estimates and revisions related to changes in commodity prices, asset purchases and new discoveries and field extensions. The Company's 2001 reserve replacement percentage was

primarily impacted by asset purchases and new discoveries and field extensions while the 2000 reserve replacement percentage was primarily impacted by revisions related to changes in commodity prices.

Description of Properties

As of December 31, 2002, the Company has production and/or development and exploration operations in the United States, Argentina, Canada, South Africa and Tunisia, and exploration opportunities in Gabon.

Domestic. The Company's domestic operations are located in the Permian Basin, Mid Continent, Gulf of Mexico and onshore Gulf Coast areas of the United States. The Company also has unproved properties in Alaska. Approximately 82 percent of the Company's domestic proved reserves are located in the Spraberry, Hugoton and West Panhandle fields. The mature Spraberry, Hugoton and West Panhandle fields generate substantial operating cash flow and have a portfolio of low risk infill drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally. During 2002, the Company expended $533.6 million in domestic acquisition, exploration and development drilling activities. The Company has budgeted approximately $300 million for domestic acquisition, exploration and development drilling expenditures for 2003.

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 per Mcf. The oil and gas are produced from three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. The center of the Spraberry field was unitized in the late 1950's and early 1960's by the major oil companies; however, until the late 1980's there was very limited development activity in the field. Since 1989, the Company has focused its development drilling activities in the unitized portion of the Spraberry field due to the dormant condition of the properties. The Company believes the area offers excellent opportunities to enhance oil and gas reserves because of the hundreds of undeveloped infill drilling locations, many of which are reflected in the Company's proved undeveloped reserves, and the ability to reduce operating expenses through economies of scale.

During 2002, the Company placed 89 Spraberry wells on production, drilled one developmental dry hole and, at December 31, 2002, had two wells in progress. The Company plans to drill approximately 150 development wells in the Spraberry field during 2003.

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's Hugoton properties represent approximately 13 percent of the proved reserves in the field and are located on approximately 257,000 gross acres (237,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, about 1,000 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, that service its production from the Hugoton field. Such ownership allows the Company to control the production, gathering, processing and sale of its gas and associated NGLs.

The Company's Hugoton operated wells are capable of producing approximately 97 MMcf of wet gas per day (i.e., gas production at the wellhead before processing and before reduction for royalties), although actual production in the Hugoton field is limited by allowables set by state regulators. The Company estimates that it and other major producers in the Hugoton field produced at or near capacity in 2002. During 2002, the Company completed four development wells in the Hugoton field and plans for 2003 include approximately 30 wells to be drilled.

The Company is continuing to evaluate the feasibility of infill drilling into the Council Grove Formation and may submit an application to the Kansas Corporation Commission to allow infill drilling. Such infill drilling may increase production from the Company's Hugoton properties. However, until an application has been approved, the Company will not reflect any of the infill drilling locations as proved undeveloped reserves. There can be no assurance that the application will be filed or approved, or as to the timing of such approval if granted.

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas where initial production commenced in 1918. 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 1,300 Btu per Mcf and is produced from approximately 600 wells on more than 241,000 acres covering over 375 square miles. The Company's wellhead gas produced from the West Panhandle field contains a high quantity of NGLs, yielding relatively greater NGL volumes than realized from the Company's 1,025 Btu per Mcf content wellhead gas in its Hugoton field. In 2002, the Company purchased the remaining rights it did not already own in the field as well as the gathering system. The Company now controls the wells, production equipment, gathering system and gas processing plant for the field.

During 2002, the Company placed 40 new wells on production, drilled three developmental dry holes and had four wells in progress at December 31, 2002. The Company plans to drill approximately 100 wells in the West Panhandle field during 2003.

Gulf of Mexico area. In the Gulf of Mexico, the Company is focused on reserve and production growth through a portfolio of shelf and deepwater development projects, high-impact, higher-risk deepwater exploration drilling, shelf exploration drilling and exploitation opportunities inherent in the properties the Company currently has producing on the shelf. To accomplish this, the Company has devoted most of its domestic exploration efforts to these two areas, as well as its investment in and utilization of 3-D seismic technology. During 2002, the Company successfully drilled six development and four exploratory wells in the deepwater Gulf of Mexico and one successful exploratory well and one successful development well on the shelf. The Company also drilled two exploratory dry holes in the deepwater Gulf of Mexico and one exploratory dry hole on the shelf during 2002.

In the deepwater Gulf of Mexico, the Company has sanctioned three major development projects, one of which is now on production and two that were in progress at December 31, 2002:

- Canyon Express - The TotalFinaElf-operated Aconcagua and the Marathon-operated Camden Hills discoveries in Mississippi Canyon were jointly developed as part of the Canyon Express gas project. Production start-up occurred in late September; however, several operational and mechanical difficulties were encountered which has resulted in the Company not reaching its estimated net production level of 110 to 120 MMcf of gas per day until late January 2003.

- Devils Tower - At the Dominion-operated Devils Tower development project in Mississippi Canyon, the Company successfully drilled two wells to explore for new reserves in previously undrilled reservoirs and to further extend the previously tested zones and three development wells. During 2001, the project was sanctioned as a spar development project with the owners leasing a spar from a third party for the life of the field. Construction of the spar is in progress, the eight producing wells on Devils Tower have been drilled and are awaiting completion and production is anticipated to begin during the first quarter of 2004. The wells will be brought on sequentially with peak production expected to reach 12,000 to 15,000 BOEs per day net to the Company's 25 percent working interest.

- Falcon - The Company-operated Falcon project is on pace to be on production in April 2003. Two development wells were drilled and completed during 2002 and the final stages of the facilities fabrication and installation are currently underway. Peak production from Falcon is anticipated at rates of approximately 130 MMcf of gas per day net to the Company's 75 percent working interest.

During 2002, the Company also participated in two appraisal sidetrack wells on the Marathon-operated deepwater Gulf of Mexico Ozona Deep prospect, of which one was a discovery. The 2002 discovery sidetrack appraisal well further extended the 2001 Ozona Deep discovery that originally encountered approximately 345 feet of net oil pay in two intervals. The Company is currently evaluating possible tie-back opportunities to existing facilities in the area, the economics of which will determine future activities. The Company also successfully drilled its Dominion-operated Triton prospect near Devils Tower. Proved reserves were recorded for this prospect and it will be completed as a subsea tieback to Devils Tower. Exploration drilling near the Falcon discovery began in December 2002 with the Lightning prospect and in January 2003 on the H2.5 and Harrier prospects. The Lightning and H2.5 exploratory wells were unsuccessful; however, the Harrier prospect was announced as a discovery in late January 2003. It is anticipated that the Harrier well will be completed with a subsea tieback to Falcon within nine to 15 months. During 2003, the Company also plans to drill its Buff prospect, which is also near the Falcon discovery.

During January 2003, the Company announced a joint exploration agreement with Woodside Energy (USA) Inc. ("Woodside"), a subsidiary of Woodside Energy Ltd. of Australia, for a two-year drilling program over the shallow- water Texas shelf region of the Gulf of Mexico. Under the agreement, Woodside has taken a 50 percent working interest in 47 offshore exploration blocks operated by the Company. The agreement covers eight prospects and 19 leads and includes five exploratory wells to be drilled in 2003 and three in 2004. Most of the wells to be drilled under the agreement will target gas plays below 15,000 feet. The eight wells to be drilled by the parties in 2003 and 2004 are on prospects generated and leased by the Company since 1997. Additionally, the Company and Woodside will evaluate for potential inclusion in the drilling program shallower gas prospects on the Gulf of Mexico shelf on other blocks covered by the leases.

Onshore Gulf Coast area. The Company has focused its drilling efforts in this area on the Pawnee field in the Edwards Reef trend in South Texas. The Company drilled six development wells at Pawnee during 2002, had one well in progress at year end and plans to drill seven wells in 2003.

Alaska area. During the fourth quarter of 2002, the Company signed an agreement with Armstrong Resources LLC under which the Company was assigned a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope. The leases cover approximately 14,000 undeveloped acres between the Kuparuk River unit and Thetis Island. The Company plans to drill up to three exploratory wells during the first quarter of 2003. The wells will test an area that the Company believes is prospective for oil in the same sands as the offsetting Kuparuk River unit eight to ten miles to the southeast. The Kuparuk River unit was discovered in 1969 and is estimated to hold 2.5 billion barrels of recoverable oil. No wells have been drilled on the acreage covered by the Company's leases to date, but wells drilled just outside the perimeter of the acreage have encountered the primary target Kuparuk "C" sands and were oil-bearing. The acreage is offshore in approximately five to ten feet of water. Drilling plans call for grounded sea ice pad locations that will be accessed via ice roads from Oliktok Point dock. All sea ice operations are expected to be completed by the end of March 2003.

International. The Company's international operations are located in the Neuquen and Austral Basins areas of Argentina and the Chinchaga, Martin Creek and Lookout Butte areas of Canada. Additionally, the Company's other significant development projects, the Sable oil field located in shallow water offshore South Africa and the Adam discovery in southern Tunisia, are scheduled for first production in mid-2003. The Company has also entered into agreements to explore for oil and gas reserves in South Africa, Gabon and Tunisia. As of December 31, 2002, approximately 16 percent, three percent, one percent and one tenth of one percent of the Company's proved reserves are located in Argentina, Canada, South Africa and Tunisia, respectively.

Argentina. The Company's share of Argentine production during 2002 averaged 21.7 MBOE per day, or approximately 19 percent of the Company's equivalent production. The Company's operated production in Argentina is concentrated in the Neuquen Basin which is located about 925 miles southwest of Buenos Aires and to the east of the Andes Mountains. Oil and gas are produced primarily from the Al Norte de la Dorsal, the Al Sur de la Dorsal, the Dadin, the Loma Negra, the Anticlinal Campamento and the Estacion Fernandez Oro blocks, in each of which the Company has a 100 percent working interest. Most of the gas produced from these blocks is processed in the Company's recently completed Loma Negra gas processing plant. The Company also operates and has a 50 percent working interest in the Lago Fuego field which is located in Tierra del Fuego, an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires.

Most of the Company's non-operated production in Argentina is located in Tierra del Fuego where oil, gas and NGLs are produced from six separate fields in which the Company has a 35 percent working interest. The Company also has a 14.4 percent working interest in the Confluencia field which is located in the Neuquen Basin.

During 2002, the Company expended $35.1 million on Argentine development and exploration activities. The Company drilled 14 development wells and 17 extension/exploratory wells, of which 13 development wells and nine extension/exploratory wells were successful. Also during 2002, the Company completed its gas processing plant at Loma Negra and completed a 35 mile gas pipeline that connects the Loma Negra plant to a main gas transmission line that accesses the Buenos Aires gas market. The Company plans to spend approximately $45 million on oil and gas development and exploration opportunities in Argentina during 2003.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. Production during 2002 averaged 9.1 MBOE per day, or approximately eight percent of the Company's equivalent production. The Company continues to focus its development, exploration and acquisition activities in the core areas of northeast British Columbia and southwest Alberta. The Canadian assets are geographically concentrated, predominantly shallow gas and more than 95 percent operated by the Company in the following areas: Chinchaga, Martin Creek and Lookout Butte.

Production from the Chinchaga area in northeast British Columbia is relatively dry gas from formation depths averaging 3,400 feet. In the Martin Creek area of British Columbia, production is relatively dry gas from various reservoirs ranging from 3,700 feet to 4,300 feet. The Lookout Butte area in southwest Alberta produces gas and condensate from the Mississippian Turner Valley formation at approximately 12,000 feet.

During 2002, the Company expended $33.5 million on Canadian development, exploration and acquisition activities. The Company drilled 17 development wells and 12 exploratory wells, primarily in the Chinchaga and Martin Creek areas, of which 13 development wells and 9 exploratory wells were successful. Most of these wells were drilled during the first quarter as these areas are only accessible for drilling during the winter months. The Company plans to spend approximately $45 million on oil and gas development and exploration opportunities in Canada during 2003.

Africa. In Africa, the Company has entered into agreements to explore for oil and gas in South Africa, Gabon and Tunisia. The amended South African agreements cover over five million acres along the southern coast of South Africa, generally in water depths less than 650 feet. The Gabon agreement covers 313,937 acres off the coast of Gabon, generally in water depths less than 100 feet. The Tunisian agreements can be separated into two categories: the first includes three permits covering 2.9 million acres onshore southern Tunisia which the Company operates with a 50 percent working interest and the second includes the Anadarko-operated Anaguid permit covering 1.2 million acres onshore southern Tunisia in which the Company has a 38.7 percent working interest and the AGIP-operated Borj El Khadra permit covering 1.2 million acres onshore southern Tunisia in which the Company has a 40 percent working interest. During 2002, the Company expended $70.3 million of acquisition, development and exploration drilling and seismic capital in South Africa, Gabon and Tunisia.

South Africa. In South Africa, the Company spent $37.1 million of drilling and seismic capital to drill four successful development wells on its Petro SA-operated Sable development project. During 2003, the Company plans to complete its Sable development project with production anticipated to begin during the second quarter of 2003. Production for the first year is expected to average approximately 12,100 Bbls of oil per day net to the Company's 40 percent working interest. In addition, the Company currently plans to drill three exploration wells in South Africa during 2003.

Gabon. In Gabon, the Company spent $23.6 million of drilling and seismic capital to drill and test three additional exploratory wells on its Bigorneau South prospect, located offshore in the Southern Gabon Basin on its Olowi permit. Pioneer is the operator of the permit with a 100 percent working interest. To date, the Company has drilled and tested four successful offshore wells which have established significant oil in place. Full development of the field is expected to involve substantial capital investment underscoring the importance of confirming reservoir characteristics and productivity. Pioneer is currently seeking bids for the development of an early production system covering a limited field area which would allow the Company to gain additional information needed to design a full field development plan. The Company is also seeking improved fiscal terms from the government.

Tunisia. In Tunisia, the Company spent $8.2 million of acquisition, drilling and seismic capital primarily to acquire a 40 percent interest in and drill an exploration well on the AGIP-operated Borj El Khadra permit. This well encountered several oil and gas productive zones that tested up to 6,000 Bbls of oil per day. The Company plans to complete the construction of a 15 kilometer flowline from the discovery to an AGIP-operated facility during the third quarter of 2003, allowing production to begin from the initial well shortly thereafter. A development well is scheduled to be drilled in the fourth quarter of 2003. In addition to this development project, plans for Tunisia in 2003 include an exploration well to be drilled on the Company-operated Jorf permit, two exploration wells to be drilled on the Anadarko-operated Anaguid permit and an additional exploration well to be drilled on the AGIP-operated Borj El Khadra permit.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2002, 2001 and 2000. Because of normal production declines, increased or decreased drilling activities and the effects of past and future 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 table sets forth production, price and cost data with respect to the Company's properties for the years ended December 31, 2002, 2001 and 2000:

PRODUCTION, PRICE AND COST DATA (a)

Year Ended December 31,

	2002				2001				2000			
	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total
Production information:												
Annual production:												
Oil (MBbls)....	8,555	2,914	45	11,514	8,629	3,566	303	12,498	8,989	3,238	308	12,535
NGLs (MBbls)...	7,487	254	345	8,086	7,232	200	368	7,800	7,883	193	303	8,379
Gas (MMcf).....	84,811	28,551	17,653	131,015	77,609	31,830	18,426	127,865	83,930	35,695	16,219	135,844
Total (MBOE)...	30,177	7,926	3,333	41,436	28,796	9,071	3,742	41,609	30,861	9,380	3,314	43,555
Average daily production:												
Oil (Bbls).....	23,437	7,984	124	31,545	23,641	9,769	831	34,241	24,561	8,847	841	34,249
NGLs (Bbls)....	20,512	696	946	22,154	19,815	547	1,008	21,370	21,538	527	829	22,894
Gas (Mcf)......	232,360	78,220	48,365	358,945	212,629	87,204	50,481	350,314	229,316	97,526	44,315	371,157
Total (BOE)....	82,677	21,716	9,131	113,524	78,894	24,851	10,253	113,997	84,318	25,628	9,056	119,002
Average prices, including hedge results:												
Oil (per Bbl)..	$ 23.66	$ 20.63	$22.26	$ 22.89	$ 24.34	$23.79	$ 21.87	$ 24.12	$ 22.07	$29.09	$27.50	$ 24.01
NGLs (per Bbl).	$ 13.77	$ 14.56	$16.77	$ 13.92	$ 16.88	$19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$24.32	$ 20.27
Gas (per Mcf)..	$ 3.16	$ .48	$ 2.50	$ 2.49	$ 4.10	$ 1.31	$ 2.86	$ 3.23	$ 3.50	$ 1.19	$ 2.88	$ 2.81
Revenue (per BOE)	$ 19.00	$ 9.79	$15.27	$ 16.94	$ 22.56	$14.36	$ 17.94	$ 20.36	$ 21.04	$15.03	$18.85	$ 19.58
Average prices, excluding hedge results:												
Oil (per Bbl)..	$ 23.85	$ 20.33	$22.26	$ 22.95	$ 24.56	$22.40	$ 21.87	$ 23.88	$ 28.76	$29.09	$27.50	$ 28.81
NGLs (per Bbl).	$ 13.77	$ 14.56	$16.77	$ 13.92	$ 16.88	$19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$24.32	$ 20.27
Gas (per Mcf)..	$ 3.02	$ .48	$ 2.40	$ 2.38	$ 3.96	$ 1.31	$ 3.27	$ 3.20	$ 3.73	$ 1.19	$ 3.45	$ 3.03
Revenue (per BOE)	$ 18.65	$ 9.68	$14.77	$ 16.63	$ 22.26	$13.81	$ 19.95	$ 20.21	$ 23.63	$15.03	$21.65	$ 21.63
Average costs:												
Production costs (per BOE):												
Lease operating	$ 3.21	$ 1.61	$ 2.64	$ 2.87	$ 2.76	$ 2.64	$ 3.01	$ 2.76	$ 2.45	$ 2.30	$ 2.53	$ 2.42
Taxes:												
Production...	.71	.13	-	.54	.98	.28	-	.74	.99	.30	-	.77
Ad valorem...	.75	-	-	.54	.71	-	-	.49	.41	-	-	.29
Field fuel.....	.85	-	-	.62	1.27	-	-	.88	1.01	-	-	.71
Workover.......	.28	.01	.59	.25	.20	.01	.32	.17	.17	-	.42	.15
Total.......	$ 5.80	$ 1.75	$ 3.23	$ 4.82	$ 5.92	$ 2.93	$ 3.33	$ 5.04	$ 5.03	$ 2.60	$ 2.95	$ 4.34
Depletion expense (per BOE).....	$ 4.64	$ 5.00	$ 8.36	$ 5.01	$ 4.46	$ 5.67	$ 7.71	$ 5.02	$ 3.95	$ 5.56	$ 7.58	$ 4.57

<FN>

(a) These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years.

</FN>

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, 2002, 2001 and 2000:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2002:						
United States................	3,448	1,952	5,400	2,745	1,855	4,600
Argentina....................	694	208	902	534	142	676
Canada.......................	1	246	247	1	197	198
South Africa.................	4	-	4	2	-	2
Tunisia......................	1	-	1	-	-	-
Total.....................	4,148	2,406	6,554	3,282	2,194	5,476
As of December 31, 2001:						
United States................	3,485	1,931	5,416	2,116	1,613	3,729
Argentina....................	669	162	831	454	132	586
Canada.......................	4	299	303	3	240	243
Total.....................	4,158	2,392	6,550	2,573	1,985	4,558
As of December 31, 2000:						
United States................	3,577	1,847	5,424	2,166	1,550	3,716
Argentina....................	575	211	786	434	154	588
Canada.......................	95	234	329	45	175	220
Total.....................	4,247	2,292	6,539	2,645	1,879	4,524

<FN>

(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. Any well in which one of the multiple completions is an oil completion is classified as an oil well. As of December 31, 2002, the Company owned interests in 111 gross wells containing multiple completions.

</FN>

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2002:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty Acreage
	Gross Acres	Net Acres	Gross Acres	Net Acres	
As of December 31, 2002:					
United States:					
Onshore...................	996,896	871,234	198,729	156,815	229,686
Offshore..................	125,786	53,120	604,287	506,712	10,500
	1,122,682	924,354	803,016	663,527	240,186
Argentina....................	710,000	299,000	1,002,000	925,000	-
Canada.......................	152,000	116,000	356,000	276,000	12,000
South Africa.................	9,600	3,840	5,368,400	4,009,160	-
Gabon........................	-	-	313,937	313,937	-
Tunisia......................	-	-	5,308,498	2,402,667	-
Total....................	1,994,282	1,343,194	13,151,851	8,590,291	252,186

Drilling activities. The following table sets forth the number of gross and net productive and dry wells in which the Company had an interest that were drilled during the years ended December 31, 2002, 2001 and 2000. 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,		
	2002	2001	2000	2002	2001	2000
United States:						
Productive wells:						
Development.................	148	228	159	83.0	114.6	91.3
Exploratory.................	6	20	11	2.0	11.0	4.7
Dry holes:						
Development.................	4	15	3	3.7	14.6	1.9
Exploratory.................	3	8	3	2.1	5.1	1.6
	161	271	176	90.8	145.3	99.5
Argentina:						
Productive wells:						
Development.................	13	19	28	13.0	17.7	26.7
Exploratory.................	9	26	38	9.0	25.5	37.6
Dry holes:						
Development.................	1	1	2	1.0	1.0	2.0
Exploratory.................	8	16	16	8.0	14.0	14.5
	31	62	84	31.0	58.2	80.8
Canada:						
Productive wells:						
Development.................	13	24	17	10.4	20.3	17.9
Exploratory.................	9	12	12	9.0	10.2	9.9
Dry holes:						
Development.................	4	2	4	4.0	2.0	2.5
Exploratory.................	3	13	2	3.0	11.8	1.9
	29	51	35	26.4	44.3	32.2
Africa:						
Productive wells:						
Development.................	4	-	-	1.6	-	-
Exploratory.................	4	3	-	3.4	2.4	-
Dry holes:						
Development.................	-	-	-	-	-	-
Exploratory.................	-	3	1	-	1.9	1.0
	8	6	1	5.0	4.3	1.0
Total.......................	229	390	296	153.2	252.1	213.5
Success ratio (a)...............	90%	85%	90%	86%	80%	88%

<FN>

(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.

</FN>

The following table sets forth information about the Company's wells upon which drilling was in progress on December 31, 2002:

	Gross Wells	Net Wells
United States:		
Development	7	6.5
Exploratory	-	-
	7	6.5
Argentina:		
Development	3	3.0
Exploratory	6	6.0
	9	9.0
Canada:		
Development	4	4.0
Exploratory	4	4.0
	8	8.0
Total	24	23.5

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings, which 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 litigation incidental to its business. The claims for damages from such other legal actions are not in excess of 10 percent of the Company's current assets and the Company believes none of these actions to be material.

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 2002.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

The Company's common stock is listed and traded on the New York Stock Exchange under the symbol "PXD". The following table sets forth, for the periods indicated, the high and low sales prices for the Company's common stock, as reported in the New York Stock Exchange composite transactions. The Company's $575 million credit agreement restricts the Company from paying or declaring dividends on common stock and certain other payments in excess of an aggregate $50 million annually. The Company's board of directors did not declare dividends to the holders of the Company's common stock during 2002 or 2001. The Company's board of directors has no current plans to declare dividends during the foreseeable future.

	High	Low
Year ended December 31, 2002:		
Fourth quarter	$ 27.50	$ 21.70
Third quarter	$ 26.23	$ 19.50
Second quarter	$ 26.05	$ 20.00
First quarter	$ 22.30	$ 16.10
Year ended December 31, 2001:		

Fourth quarter	$ 19.70	$ 13.22
Third quarter	$ 19.38	$ 12.62
Second quarter	$ 23.05	$ 14.30
First quarter	$ 20.24	$ 15.45

On February 14, 2003, the last reported sales price of the Company's common stock, as reported in the New York Stock Exchange composite transactions, was $24.25 per share.

As of February 14, 2003, the Company's common stock was held by approximately 30,951 holders of record.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data 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,				
	2002	2001	2000	1999	1998
	(in millions, except per share data)				
Statement of Operations Data:					
Revenues and other income:					
Oil and gas	$ 701.8	$ 847.0	$ 852.7	$ 644.6	$ 711.5
Interest and other (a)	11.2	21.8	25.8	89.7	10.4
Gain (loss) on disposition of assets, net	4.4	7.7	34.2	(24.2)	(.4)
	717.4	876.5	912.7	710.1	721.5
Costs and expenses:					
Oil and gas production	199.6	209.7	189.3	159.5	223.5
Depletion, depreciation and amortization	216.4	222.6	214.9	236.1	337.3
Impairment of properties and facilities	-	-	-	17.9	459.5
Exploration and abandonments	85.9	127.9	87.5	66.0	121.9
General and administrative	48.4	37.0	33.3	40.2	82.6
Reorganization	-	-	-	8.5	33.2
Interest	95.8	131.9	162.0	170.3	164.3
Other (b)	17.2	39.6	67.2	34.7	30.0
	663.3	768.7	754.2	733.2	1,452.3
Income (loss) before income taxes and extraordinary items	54.1	107.8	158.5	(23.1)	(730.8)
Income tax benefit (provision)	(5.1)	(4.0)	6.0	.6	(15.6)
Income (loss) before extraordinary items	49.0	103.8	164.5	(22.5)	(746.4)
Extraordinary items (c)	(22.3)	(3.8)	(12.3)	-	-
Net income (loss)	$ 26.7	$ 100.0	$ 152.2	$ (22.5)	$ (746.4)
Income (loss) before extraordinary items per share:					
Basic	$ .44	$ 1.05	$ 1.65	$ (.22)	$ (7.46)
Diluted	$ .43	$ 1.04	$ 1.65	$ (.22)	$ (7.46)
Net income (loss) per share:					
Basic	$ .24	$ 1.01	$ 1.53	$ (.22)	$ (7.46)
Diluted	$ .23	$ 1.00	$ 1.53	$ (.22)	$ (7.46)
Dividends per share	$ -	$ -	$ -	$ -	$ .10
Weighted average shares outstanding:					
Basic	112.5	98.5	99.4	100.3	100.1

Diluted	114.3	99.7	99.8	100.3	100.1
Statement of Cash Flows Data:					
Cash flows from operating activities	$ 332.2	$ 475.6	$ 430.1	$ 255.2	$ 314.1
Cash flows from investing activities	$ (508.1)	$ (422.7)	$ (194.5)	$ 199.0	$ (517.0)
Cash flows from financing activities	$ 170.9	$ (64.0)	$ (244.1)	$ (479.1)	$ 190.9
Balance Sheet Data (as of December 31):					
Working capital (deficit)	$ (127.5)	$ 27.4	$ (25.1)	$ (13.7)	$ (324.8)
Property, plant and equipment, net	$3,168.4	$2,784.3	$2,515.0	$2,503.0	$3,034.1
Total assets	$3,455.1	$3,271.1	$2,954.4	$2,929.5	$3,481.3
Long-term obligations	$1,796.9	$1,743.7	$1,804.5	$1,914.5	$2,101.2
Total stockholders' equity	$1,374.9	$1,285.4	$ 904.9	$ 774.6	$ 789.1

<FN>

(a) 1999 includes $41.8 million of option fees and liquidated damages and $30.2 million of income associated with an excise tax refund.

(b) Other expense for 2002 includes $6.9 million and $2.6 million for the remeasurement of Argentine peso-denominated net monetary assets and Canadian gas marketing losses, respectively. Other expense for 2001 includes $11.5 million, $9.9 million and $7.7 million of charges for changes in the fair values of derivatives excluded from hedge accounting treatment; Canadian gas marketing losses; and the remeasurement of Argentine peso-denominated net monetary assets and adjustments to reduce the carrying value of Argentine lease and well equipment inventory to market value, respectively. Other expense for 2000, 1999 and 1998 include noncash mark-to-market charges for changes in the fair values of non-hedge financial instruments of $58.5 million, $27.0 million and $21.2 million, respectively.

(c) The Company's extraordinary items represent losses from the early extinguishment of debt. See Notes B and E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's extraordinary items.

</FN>

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

2002 Financial and Operating Performance

The year ended December 31, 2002 was highlighted by favorable commodity prices and continued strengthening of North American gas fundamentals; the issuance of 11.5 million shares of common stock to fund strategic acquisitions in the Company's core areas of the West Panhandle gas field and the Gulf of Mexico Falcon field development project; initial production from the Canyon Express gas project; continued development of the deepwater Gulf of Mexico Devils Tower and Falcon fields and the Sable oil field offshore South Africa; indications that the Argentine economy and currency may be stabilizing; continued evaluation of the Gabon discovery; an oil discovery in Tunisia; the acquisition of undeveloped property interests in Alaska; the completion of a public offering of $150 million of 7-1/2 percent senior notes that will mature in 2012; and repurchases of $61.0 million of higher yielding funded debt to reduce the Company's future costs of capital.

During the years ended December 31, 2002, 2001 and 2000, the Company recorded net income of $26.7 million, $100.0 million and $152.2 million ($.23, $1.00 and $1.53 per diluted share), respectively. Compared to 2001, the Company's 2002 total revenues and other income decreased by $159.0 million, or 18 percent, including a $145.2 million decrease in oil and gas revenues. The decrease in oil and gas revenues was due to decreases of five percent, 19 percent and 23 percent in average oil, NGL and gas prices, respectively, including the effects of commodity price hedges.

Compared to 2001, the Company's 2002 total costs and expenses decreased by $105.4 million, or 14 percent. The decrease in total costs and expenses was primarily reflective of a $42.0 million decrease in exploration and abandonments expense, primarily due to the allocation of a larger percentage of the Company's 2002 capital budget to the development of the Company's Canyon Express, Falcon, Devils Tower and Sable projects; a $36.1 million decrease in interest expense, primarily due to declining underlying market interest rates, interest savings associated with the replacement of higher yielding senior notes and capital cost obligations with lower yielding senior notes and corporate credit facility indebtedness, interest rate hedge gains and increased interest capitalized on significant capital projects; and a $22.3 million decrease in other expense, primarily due to declines in derivative mark-to-market provisions, gas marketing losses and bad debt expense.

During the year ended December 31, 2002, the Company's net cash provided by operating activities decreased to $332.2 million, as compared to $475.6 million during 2001 and $430.1 million during 2000. The decrease in net cash provided by operating activities during 2002 was primarily due to declines in oil, NGL and gas prices as discussed above.

During 2002, successful capital investment activities increased the Company's proved reserves to 736.7 MMBOE, reflecting the effects of strategic acquisitions of properties in the Company's core operating areas and a successful drilling program which resulted in the replacement of 258 percent of production at an acquisition and finding cost per BOE of $6.30. During the three years ended December 31, 2002, Pioneer has replaced 210 percent of production at an acquisition and finding cost per BOE of $6.24. Costs incurred for the year ended December 31, 2002 totaled $672.5 million, including $195.5 million of proved and unproved property acquisitions and $477.0 million of exploration and development drilling and seismic expenditures.

During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest in and operates the Falcon field development and related exploration blocks. Also during 2002, the Company completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded $100.4 million to proved oil and gas properties, $3.8 million to unproved oil and gas properties and $1.9 million to assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash.

See "Results of Operations" and "Capital Commitments, Capital Resources and Liquidity", below, for more in-depth discussions of the Company's oil and gas producing activities, including discussions pertaining to oil and gas production volumes, prices, hedging activities, costs and expenses, capital commitments, capital resources and liquidity.

2003 Outlook

Commodity prices. During 2001, commodity prices declined from historically high levels at the beginning of the year to historically moderate levels by year end. World oil prices increased during 2002 in response to political unrest and supply disruptions in the Middle East and Venezuela. During the third and fourth quarters of 2002, North American gas prices improved as market fundamentals strengthened. The Company's outlook for 2003 commodity prices is uncertain. Significant factors that will impact 2003 commodity prices include the final resolution of issues currently impacting Iraq and Venezuela, the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to manage oil supply through export quotas and overall North American gas supply and demand fundamentals. Pioneer will continue to moderate its debt levels, follow cost management measures and strategically hedge oil and gas price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues.

As of December 31, 2002, the Company had hedged 22,236 barrels per day

("Bblpd") of 2003 oil production under swap contracts with a weighted average fixed price to be received of $24.45 per Bbl. The Company had also hedged 230,000 Mcf per day of 2003 gas production under swap contracts with a weighted average fixed price to be received of $3.76 per MMBtu. During January 2003, the Company increased its 2003 commodity hedge positions by entering into 6,000 Bblpd of March oil swap contracts with average per Bbl fixed prices of $33.51. Additionally, at December 31, 2002 the Company has deferred oil hedge losses of $.5 million that will be recognized as reductions to oil revenue during the last eight months of 2003 and $72.5 million of gas hedge gains that will be recognized as increases to gas revenue during 2003. 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 open hedge positions at December 31, 2002. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

First quarter 2003. Based on current estimates, the Company expects that its first quarter worldwide production will average 120 to 128 MBOE per day. Included in the mid-point of the estimate is 95 MMcf per day, net to the Company from Canyon Express. First quarter production costs are expected to average $5.10 to $5.40 per BOE based on recent NYMEX strip prices for oil and gas. Depreciation, depletion and amortization expense is expected to average $5.75 to $6.00 per BOE, and total exploration and abandonment expense is expected to be $20 million to $50 million. General and administrative expense is expected to be $16 million to $17 million during the first quarter of 2003, $2 million to $3 million of which relates to estimated additional performance-based compensation costs. Interest expense is expected to be $24 million to $26 million. Interest capitalized during the first quarter of 2003 will be significantly less than interest capitalized during the first three quarters of 2002 as the Company's largest capital project for which interest was being capitalized, the Canyon Express development project, was put into production during September 2002. Additionally, during February 2003, the Company entered into interest rate swap contracts to hedge a portion of the fair value of its 9-5/8 percent senior notes. Under the terms of the interest rate swap contracts, the Company will receive a fixed annual rate of 9-5/8 percent on $250 million notional amount and will pay the counterparties a variable rate on the notional amount equal to the six-month LIBOR, reset semi-annually, plus a weighted average margin of 566.4 basis points. Income taxes, principally in Argentina, are expected to be approximately $2 million as the Company benefits from the carryforward of net operating losses in the United States and Canada.

Production growth. The Company expects that its annual 2003 worldwide production will be approximately 165 MBOE per day, an increase of 45 percent over 2002 levels. The growth in production during 2003 includes initial production during the second quarter from the Company's deepwater Gulf of Mexico Falcon gas project and the Sable oil project in South Africa, coupled with peak rates of production from Canyon Express and increases in production from the Company's core properties in the United States, Argentina and Canada due to an aggressive development drilling program with approximately twice as many wells anticipated in 2003 versus 2002.

Capital expenditures. During 2003, the Company's budget for oil and gas producing activities is expected to range from $450 million to $550 million, of which approximately 35 percent has been budgeted for exploration expenditures and 65 percent has been budgeted for development drilling and facility costs. The Company's 2003 capital budget is allocated approximately 60 percent to the

United States, nine percent to Argentina and Canada and 22 percent to Africa. The Company's 2003 capital budget includes $35 million of remaining development capital to complete the Falcon and Devils Tower development projects in the deepwater Gulf of Mexico and the Sable oil project offshore South Africa. Aggressive development drilling programs in the Company's core Spraberry oil field, Hugoton and West Panhandle gas fields, the United States Gulf Coast, Argentina and Canada will resume with approximately twice as many wells anticipated in 2003 versus 2002. During 2003, the Company has planned exploration drilling in the Gulf of Mexico, the onshore Gulf Coast area, Alaska, Canada, Gabon, Tunisia and South Africa. During the years ended December 31, 2004 and 2005, the Company expects to expend approximately $172 million and $151 million, respectively, of capital for development drilling and facility costs related to its proved undeveloped reserves.

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with accounting principles that are generally accepted in the United States ("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 judgements and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. Following is a discussion of the Company's most critical accounting estimates, judgements and uncertainties that are inherent in the Company's application of GAAP:

Accounting for oil and gas producing activities. The accounting for and disclosure of oil and gas producing activities requires the Company's management to choose between GAAP alternatives and to make judgements about estimates of future uncertainties.

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 2002, 2001 and 2000, the Company recognized exploration, abandonment, geological and geophysical expense of $85.9 million, $127.9 million and $87.6 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, 2002 was based on evaluations 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. The Company's proved reserve information included in this Report as of December 31, 2001 and 2000 was based on evaluations prepared by the Company's engineers. Estimates prepared by other 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 material revisions to the estimate.

The Company's stockholders should not assume that the present value of future net cash flows is the current market value of the Company's estimated

proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves 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.

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 uneconomic to drill for and produce higher cost fields. In addition, the decline in proved reserve estimates may impact the outcome of the Company's assessment of its oil and gas producing properties for impairment.

Impairment of proved oil and gas properties. The Company reviews its long-lived proved properties to be held and used whenever management judges 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 management's outlook of future commodity prices and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment by depletable pool, which is the lowest level at which depletion of proved properties is calculated.

Impairment of unproved oil and gas properties. Management periodically assesses individually significant 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 impact the amount and timing of impairment provisions.

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 international operations except Canada. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentine economic and currency measures. The accounting for and remeasurement of the Company's Argentine balance sheets as of December 31, 2002 and 2001 reflect management's assumptions regarding some uncertainties unique to Argentina's current economic situation. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the assumptions utilized in the preparation of these financial statements. The Argentine economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, (i) the realized prices the Company receives for the commodities it produces and sells; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities.

Deferred tax asset valuations. Management periodically assesses the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks by tax jurisdiction. Such estimates are inherently imprecise. Many assumptions are utilized in the assessments that may prove to be materially incorrect in the future.

New Accounting Pronouncements

During June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amends Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19") to require 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 capitalized as part of the carrying value of the long-lived asset. Under the provisions of SFAS 19, asset retirement obligations are recognized using a cost-accumulation approach. The Company currently records significant asset retirement obligations through the unit-of-production method, except for such liabilities that were assumed in business combinations, which were recorded at their estimated fair values. The Company adopted the provisions of SFAS 143 on January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $13.8 million increase in the carrying values of proved properties, (ii) a $26.3 million decrease in accumulated depreciation, depletion, and amortization of property, plant and equipment, (iii) a $1.0 million increase in current abandonment liabilities and (iv) a $22.4 million increase in noncurrent abandonment liabilities. The net impact of items (i) through (iv) was to record a gain of $16.7 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003.

During April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. The Company adopted the provisions of SFAS 145 on January 1, 2003. The adoption of the provisions of SFAS 145 is not expected to affect the Company's future financial position or liquidity. Upon adoption of the provisions of SFAS 145, gains or losses from the early extinguishment of debt recognized in the Company's consolidated statements of operations for the years ended December 31, 2002, 2001 and 2000 will be reclassified to other revenues or other expense and included in the determination of the income (loss) from continuing operations of those periods.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled $701.8 million during 2002, as compared to $847.0 million during 2001 and $852.7 million during 2000, representing a 17 percent decrease from 2001 to 2002. The revenue decrease from 2001 to 2002 was due to year-on-year worldwide average gas, NGL and oil price declines of 23 percent, 19 percent and five percent, respectively, including the effects of gas and oil price hedges; and an eight percent decline in worldwide oil production, offset by worldwide NGL and gas production increases of four percent and two percent, respectively. The revenue decrease from 2000 to 2001 was due to a four percent decline in BOE production and a 15 percent decline in NGL price, partially offset by a 15 percent increase in gas price, including the effects of gas hedges. The declines in 2001 sales volumes were primarily attributable to normal well production declines.

The following table provides production and price data relevant to the analysis of the Company's revenues from oil and gas operations:

	Year ended December 31,		
	2002	2001	2000
Production:			
Oil (MBbls)	11,514	12,498	12,535
NGLs (MBbls)	8,086	7,800	8,379
Gas (MMcf)	131,015	127,865	135,843
Total (MBOE)	41,436	41,609	43,555
Average daily production:			
Oil (Bbls)	31,545	34,241	34,249
NGLs (Bbls)	22,154	21,370	22,894
Gas (Mcf)	358,945	350,314	371,157
Total (BOE)	113,524	113,997	119,002
Average reported prices:			
Oil (per Bbl)			
United States	$ 23.66	$ 24.34	$ 22.07
Argentina	$ 20.63	$ 23.79	$ 29.09

Canada....................................	$ 22.26	$ 21.87	$ 27.50
Worldwide.................................	$ 22.89	$ 24.12	$ 24.01
NGL (per Bbl)			
United States.............................	$ 13.77	$ 16.88	$ 20.05
Argentina.................................	$ 14.56	$ 19.29	$ 22.91
Canada....................................	$ 16.77	$ 21.11	$ 24.32
Worldwide.................................	$ 13.92	$ 17.14	$ 20.27
Gas (per Mcf)			
United States.............................	$ 3.16	$ 4.10	$ 3.50
Argentina.................................	$ .48	$ 1.31	$ 1.19
Canada....................................	$ 2.50	$ 2.86	$ 2.88
Worldwide.................................	$ 2.49	$ 3.23	$ 2.81
Annual percentage increase (decrease) in average worldwide reported prices:			
Oil.......................................	(5)	-	56
NGL.......................................	(19)	(15)	74
Gas.......................................	(23)	15	48

Hedging activities. The commodity prices that the Company reports are based on the market price received for the commodities adjusted by the results of the Company's hedging activities. The Company utilizes commodity derivative contracts (swaps and collars) 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. The effective portions of changes in the fair values of the Company's commodity price hedge derivatives are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedge derivatives 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 2002, 2001 and 2000 from the Company's hedging activities, the Company's open hedge positions at December 31, 2002 and descriptions of the Company's hedge and non-hedge commodity derivatives. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosure about the Company's commodity related derivative financial instruments.

Interest and other revenue. The Company recorded interest and other income totaling $11.2 million, $21.8 million and $25.8 during 2002, 2001 and 2000, respectively. The Company's interest and other income was comprised of revenue that was not directly attributable to oil and gas producing activities or oil and gas property divestitures. See Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding interest and other income.

Gain (loss) on disposition of assets. During the year ended December 31, 2002, the Company realized $118.9 million of cash proceeds from asset divestitures and, associated therewith, recorded net gains of $4.4 million. The proceeds derived from asset divestitures during 2002 included $91.3 million from the early termination of hedge derivatives, $20.9 million from the cash settlement of a gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $2.0 million from the sale of other corporate assets. The Company recorded a gain of $2.8 million associated with the sale of the gas properties in Oklahoma and a gain of $1.6 million from the sale of other corporate assets. The proceeds from the early termination of hedge derivatives represent deferred hedge gains and losses that will be recognized as increases or decreases to future interest expenses or future oil and gas revenues. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the amortization of deferred hedge gains and losses.

During the year ended December 31, 2001, the Company realized $113.5 million of cash proceeds from asset divestitures and, associated therewith, recorded net gains of $7.7 million. The proceeds derived from asset divestitures during 2001 included $85.4 million from the early termination of hedge derivatives, $12.7 million from the sale of the Company's remaining holdings in the common stock of a non-affiliated entity, $12.0 million from the sale of certain oil properties in Canada and $3.4 million from the sale of other corporate assets. The Company recorded a gain of $8.1 million from the sale of the remaining holdings in the common stock of the non-affiliated entity, a loss of $1.1 million from the sales of oil and gas properties and a gain of $.7 million from the sale of other corporate assets.

During 2000, the Company completed the divestiture of certain assets for proceeds of $102.7 million. Associated therewith, the Company recorded a net gain on disposition of assets of $34.2 million. The 2000 divestitures included the sale of common stock of a non-affiliated entity for net proceeds of $59.7 million, from which the Company recognized a gain on disposition of assets of $34.3 million. The Company also sold certain oil and gas producing properties and other assets during 2000 for proceeds of $43.0 million, from which the Company recognized a loss on disposition of assets of $.1 million.

The net cash proceeds from asset divestitures during 2002, 2001 and 2000 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and to reduce outstanding indebtedness. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Production costs. Total production costs per BOE decreased in 2002 by four percent and increased in 2001 by 16 percent. In general, lease operating expenses and workover expenses represent the components of production costs over which the Company has management control, while production taxes, ad valorem taxes and field fuel expenses are directly related to commodity price changes. The decrease in production costs during 2002 was primarily due to decreases in field fuel expense and production taxes as a result of lower North American average gas prices and lower Argentine lease operating expenses resulting from lower Argentine expenses on a U.S. dollar equivalent basis due to the devaluation of the Argentine peso versus the U.S. dollar, partially offset by moderately higher workover expenses, ad valorem taxes (which are computed using prior year average annual commodity prices) and declines in the third party gas processing and treating margin component of lease operating expense. The increase in production costs during 2001 was primarily due to increases in field fuel expense as a result of higher North American average gas prices, higher ad valorem taxes and to declines in the third party gas processing and treating margin component of lease operating expenses. The following table provides the components of the Company's production costs during the years ended December 31, 2002, 2001 and 2000:

	Year Ended December 31,		
	2002	2001	2000
		(per BOE)	
Lease operating expenses	$ 2.87	$ 2.76	$ 2.42
Taxes:			
Production	.54	.74	.77
Ad valorem	.54	.49	.29
Field fuel expenses	.62	.88	.71
Workover expenses	.25	.17	.15
Total production costs	$ 4.82	$ 5.04	$ 4.34

Depletion, depreciation and amortization expense. The Company's total depletion, depreciation and amortization expense per BOE was $5.22, $5.35 and $4.93 for the years ended December 31, 2002, 2001 and 2000, respectively. Depletion expense, the largest component of depletion, depreciation and amortization, was $5.01, $5.02 and $4.57 per BOE during the years ended December 31, 2002, 2001 and 2000, respectively, and depreciation and amortization of other property and equipment was $.21, $.33 and $.36 per BOE during each of the respective years. The decrease in depreciation and amortization of other property and equipment during 2002 was primarily comprised of decreases associated with fully amortized information technology assets. During 2001, the increase in per BOE depletion expense was primarily associated with decreases in United States production, which had a lower cost basis relative to combined Argentine and Canadian per BOE cost basis, and to downward revisions to proved reserves as a result of lower commodity prices.

Exploration, abandonments, geological and geophysical costs. Exploration, abandonments, geological and geophysical costs totaled $85.9 million, $127.9 million and $87.6 million for the years ended December 31, 2002, 2001 and 2000, respectively. The following table sets forth the components of the Company's 2002, 2001 and 2000 exploration and abandonments/geological and geophysical costs:

	United States	Argentina	Canada	Other Foreign	Total
			(in thousands)		
Year Ended December 31, 2002:					
Geological and geophysical costs........	$ 22,761	$ 4,138	$ 3,544	$ 7,223	$ 37,666
Exploratory dry holes...................	32,557	3,294	1,220	(539)	36,532
Leasehold abandonments and other........	7,637	2,874	1,077	108	11,696
	$ 62,955	$ 10,306	$ 5,841	$ 6,792	$ 85,894
Year Ended December 31, 2001:					
Geological and geophysical costs........	$ 29,620	$ 6,541	$ 2,373	$ 13,678	$ 52,212
Exploratory dry holes...................	34,883	6,040	5,473	10,432	56,828
Leasehold abandonments and other........	5,546	11,276	2,036	8	18,866
	$ 70,049	$ 23,857	$ 9,882	$ 24,118	$127,906
Year Ended December 31, 2000:					
Geological and geophysical costs........	$ 22,033	$ 6,881	$ 2,273	$ 7,761	$ 38,948
Exploratory dry holes...................	11,745	6,987	887	8,396	28,015
Leasehold abandonments and other........	7,089	11,520	1,971	7	20,587
	$ 40,867	$ 25,388	$ 5,131	$ 16,164	$ 87,550

The decrease in 2002 exploration, abandonments, geological and geophysical costs reflected a decline in Argentine exploration activities as the Company monitored and assessed the economic environment and risks associated with Argentina; a decline in exploratory dry holes and geological and geophysical costs in Africa, as the Company assessed its exploratory successes in Gabon and Tunisia; and the allocation of a larger percentage of the Company's 2002 capital budget to the development of its significant discoveries in the Gulf of Mexico and offshore South Africa. The increase in 2001 exploration costs, as compared to 2000, was primarily due to increased geological and geophysical costs that were supportive of exploratory drilling, increased exploratory drilling in the Gulf of Mexico and Argentina and an exploratory dry hole drilled in Tunisia. Approximately 20 percent of the Company's 2002 costs incurred for oil and gas producing activities were exploration costs as compared to 34 percent in 2001 and 38 percent in 2000.

General and administrative expenses. The Company's general and administrative expenses totaled $48.4 million ($1.17 per BOE), $37.0 million ($.89 per BOE) and $33.3 million ($.76 per BOE) during the years ended December 31, 2002, 2001 and 2000, respectively. The increase in administrative expense during 2002 as compared to 2001 was primarily due to the elimination of operating overhead being charged by the Company to the 42 affiliated partnerships that were merged into a wholly-owned subsidiary of the Company during December 2001 (see "Financial and Operating Performance" and Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the 2001 merger). Additionally, the Company awarded 645,445 shares of restricted stock to directors, officers and key employees as part of the Company's compensation program. The Company recorded $16.2 million of deferred compensation associated with the restricted stock awards, which amount will be amortized to compensation expense during the vesting periods of the awards. Amortization of the deferred costs of the restricted stock increased general and administrative expenses by $1.9 million in 2002. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for

information regarding the restricted stock awards and their vesting periods. The increase in general and administrative expense during 2001, as compared to 2000, was primarily due to an increase in compensation expense.

Interest expense. Interest expense was $95.8 million, $132.0 million and $162.0 million for the years ended December 31, 2002, 2001 and 2000, respectively. The decline in 2002 interest expense as compared to 2001, was primarily due to incremental interest savings of $18.0 million from the Company's interest rate hedging program; a $6.3 million increase in interest capitalized; interest savings from the retirement of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior subordinated notes during the third quarter of 2001 and $38.7 million of the Company's 9-5/8 percent senior notes during the fourth quarter of 2001; interest savings from the repurchase of $47.1 million of 9-5/8 percent senior notes and $13.9 million of 8-7/8 percent senior notes during 2002; interest savings from the repayment of the $45.2 million West Panhandle gas field capital obligation in July 2002 which bore interest at an annual rate of 20 percent; and interest savings from reductions in underlying market interest rates. The decrease in interest expense for 2001 as compared to 2000 was primarily due to incremental interest savings of $7.0 million from the Company's interest rate hedging program; a $6.0 million increase in interest capitalized; and interest savings associated with the redemption of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior subordinated notes and $38.7 million of the Company's 9-5/8 percent senior notes.

As is discussed in "2003 Outlook" above, capitalized interest will decline during 2003, as compared to 2002 levels, primarily due to the completion of the Canyon Express development project during September 2002 and the anticipated completion of the Falcon and Sable development projects during the second quarter of 2003. Additionally, 2003 interest expense will be impacted by fair value hedges of the Company's 9-5/8 percent senior notes that were initiated by the Company during February 2003 and for which more detailed information is provided in "2003 Outlook" and in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". See Note E 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, interest expense and extraordinary items.

Other expenses. Other expenses were $17.3 million during 2002, as compared to $39.6 million during 2001 and $67.2 million during 2000. Other expenses during 2002 were primarily comprised of a $6.9 million charge from the remeasurement of the Company's Argentine peso-denominated net monetary assets and liabilities and $2.5 million of marketing losses incurred to transport and sell purchased Canadian gas to a Chicago, Illinois sales point. See Note B and Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding currency remeasurement and gas transportation commitments.

Other expenses in 2001 include $11.4 million of commodity derivative settlements that did not qualify for hedge treatment under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"; $9.9 million of marketing losses incurred to transport and sell purchased Canadian gas to a Chicago, Illinois sales point; $7.7 million of losses from the remeasurement of the Company's Argentine peso-denominated net monetary assets and an adjustment to reduce the carrying value of Argentine lease and well equipment inventory to market value; $6.0 million of bad debt expense related to derivative contracts with Enron North America Corp. and $4.6 million of other expenses.

The primary component of other expense during 2000 was $58.5 million of mark-to-market losses on derivative contracts that did not qualify for hedge accounting treatment, including $43.9 million of losses on derivative contracts that matured during 2000 and $14.6 million of losses associated with the Company's Btu swap agreements that mature at the end of December 2004. During 2001, the Company entered into offsetting swap agreements that had fixed the prices that are to be received and paid by the Company under the Btu swap agreements. Consequently, the Btu swap agreements are no longer sensitive to changes in oil or gas commodity prices.

Income tax provisions (benefits). The Company recognized consolidated income tax provisions of $5.1 million and $4.0 million during 2002 and 2001, respectively, and a consolidated income tax benefit of $6.0 million during 2000. The Company's consolidated tax provision for the year ended December 31, 2002 was comprised of current U.S. state and local taxes of $.2 million, current foreign taxes of $2.1 million and deferred foreign tax provisions of $2.8 million. The Company's consolidated tax provision for the year ended December 31, 2001 was comprised of current U.S. state and local taxes of $1.1 million, current foreign taxes of $10.5 million and deferred foreign tax benefits of $7.6 million. The Company's consolidated tax benefit in 2000 was comprised of a $10.6 million deferred tax benefit in Argentina, partially offset by $4.6 million of current taxes paid in Argentina.

Due to uncertainties regarding the Company's ability to realize certain of its net operating loss carryovers and tax credit carryovers prior to their scheduled expirations, the Company has established a valuation allowance of $277.2 million against those carryovers. Although the Company believes it is more likely than not that the carrying values of its remaining deferred tax assets will be realized through future taxable earnings or alternative tax planning strategies, the net deferred tax assets could be reduced further if the Company's estimate of taxable income in future periods is significantly reduced or alternative tax planning strategies are no longer viable. As a result of this situation, it is likely that the Company's effective tax rate in 2003 will be minimal in the United States and Canada and approximately 35 percent in Argentina. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's income tax, deferred tax asset valuation reserves and net operating loss carryforward expirations.

Extraordinary items. During 2002, the Company repurchased $47.1 million of its 9-5/8 percent senior notes, $13.9 million of its 8-7/8 percent senior notes and repaid a $45.2 million West Panhandle field capital cost obligation. Associated with the 2002 debt extinguishments, the Company recognized an extraordinary loss, net of taxes, of $22.3 million. During 2001, the Company redeemed the remaining $22.5 million of its outstanding 11-5/8 percent senior subordinated notes, $6.8 million of its outstanding 10-5/8 percent senior subordinated notes and repurchased $38.7 million of its 9-5/8 percent senior notes. Associated with these debt extinguishments, the Company recognized an extraordinary loss, net of taxes, of $3.8 million. During 2000, the Company replaced its prior credit facility, which was scheduled to mature in August 2002, with a new $575 million corporate credit facility due March 1, 2005 (the "Credit Agreement"). Associated therewith, the Company recognized a $12.3 million extraordinary loss on early extinguishment of debt. See "New Accounting Pronouncements", above, for information regarding future changes in the classification of the Company's extraordinary gains and losses.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital obligations. Funding for exploration, development and acquisitions 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 non-strategic assets or alternative financing sources as discussed in "Capital resources" below. Funding for the Company's working capital obligations is provided by internally-generated cash flow.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2002, 2001 and 2000 totaled $614.7 million, $529.7 million and $299.7 million, respectively. The Company's 2002 expenditures for additions to oil and gas properties were funded by $332.2 million of net cash provided by operating activities, $118.9 million of proceeds from the disposition of assets and a portion of the proceeds from the issuance of 11.5 million shares of the Company's common stock during April 2002. The Company's 2001 expenditures were internally funded by $475.6 million of net cash provided by operating activities and a portion of the Company's $113.5 million of proceeds from disposition of assets. The Company's 2000 capital expenditures were internally funded by net cash provided by operating activities.

The Company strives to maintain its indebtedness at reasonable levels in order to provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2003 is expected to range from $450 million to $550 million. The Company believes that net cash provided by operating activities during 2003 will be sufficient to fund the 2003 capital expenditures budget.

Contractual obligations, including off-balance sheet obligations. The Company's contractual obligations include long-term debt, operating leases, Btu swap agreements, terminated commodity hedges and other contracts. 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, 2002, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) $27.2 million of undrawn letters of credit issued under the Company's $575 million corporate credit facility and (ii) operating lease agreements under which the Company's future minimum lease commitments are summarized in the table below and in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". Contractual obligations for which the ultimate settlement amounts are not fixed and determinable include derivative contracts that are sensitive to future changes in commodity prices, currency exchange rates and interest rates and gas transportation commitments. See "Item

7A. Quantitative and Qualitative Disclosures About Market Risk" for a table of changes in the fair value of the Company's derivative contract assets and liabilities during the year ended December 31, 2002 and Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding gas transportation commitments. The following table summarizes the Company's payments due by period for fixed and determinable contractual obligations:

	Payments Due by Year				
	2003	2004	2005	2006-2007	Thereafter
			(in thousands)		
Long-term debt (a)............	$ -	$ -	$ 406,704	$ 161,130	$1,100,702
Operating leases (b)..........	19,364	41,553	39,375	58,924	36,338
Btu swap agreements (c)........	7,168	7,190	-	-	-
Terminated commodity hedges....	484	340	-	-	-
	$ 27,016	$ 49,083	$ 446,079	$ 220,054	$1,137,040

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

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Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of non-strategic assets. The Company expects that these resources will be sufficient to fund its capital commitments in 2003.

Operating activities. Net cash provided by operating activities during 2002, 2001 and 2000 were $332.2 million, $475.6 million and $430.1 million, respectively. Net cash provided by operating activities in 2002 decreased by $143.4 million, or 30 percent, as compared to that of 2001. The decrease in 2002 net cash provided by operating activities was principally due to declines in commodity prices, offset partially by declines in interest expense. Net cash provided by operating activities in 2001 increased by $45.5 million, or 11 percent, as compared to that of 2000. The increase in 2001 was primarily due to higher commodity prices as compared to 2000, declines in interest expense and an increase in trade receivable collections.

Financing activities. During the year ended December 31, 2002, the Company's financing activities provided $170.9 million of cash, comprised of $236.0 million of proceeds, net of issuance costs, from the sale of 11.5 million shares of the Company's common stock; $48.0 million of net borrowings of long-term debt; and $14.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. Partially offsetting these cash proceeds from financing activities were $124.2 million of payments of noncurrent liabilities and $3.3 million of debt issuance costs during 2002. In contrast, during the years ended December 31, 2001 and 2000, the Company used $64.0 million and $244.1 million, respectively, of net cash in financing activities. During the years ended December 31, 2001 and 2000, the Company used $5.1 million and $177.3 million of cash, respectively, to repay long-term debt; $53.4 million and $29.8 million, respectively, to repay noncurrent liabilities; $13.0 million and $27.3 million, respectively, to purchase treasury stock; and, during the year ended December 31, 2000, $13.8 million for deferred loan and debt issuance costs. Partially offsetting the above described net cash uses from financing activities were $7.5 million and $4.2 million of net cash provided from the exercise of long-term incentive plan stock options and employee stock purchases during the years ended December 31, 2001 and 2000, respectively.

Over the three year period ended December 31, 2002, the Company has used $134.4 million of cash for net reductions in long-term borrowings and has reduced its ratio of debt to book capitalization to 55 percent as of December 31, 2002, from 69 percent as of December 31, 1999. Additionally, the Company has entered into financing transactions with the intent of reducing its costs of capital and increasing liquidity through the extension of debt maturities.

During the years ended December 31, 2002 and 2001, the Company entered into interest rate swap contracts to hedge the fair value of its 6-1/2 percent senior notes, its 8-7/8 percent senior notes and its 8-1/4 percent senior notes. The Company also entered into interest rate swaps to hedge a portion of its interest rate risk under the Credit Agreement. In 2002 and 2001, the Company terminated its open interest rate swap portfolios to lock in the substantial fair value of the derivatives. As of December 31, 2002, the Company had $35.7 million of

deferred gains associated with the interest rate swap terminations recorded as an increase in the carrying value of the Company's long-term debt. During the years ended December 31, 2002, 2001 and 2000, net gains from the Company's interest rate swaps have reduced interest expense by $25.3 million, $7.3 million and $.3 million, respectively. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for more information about the Company's interest rate hedging activities.

As is further described in "Results of Operations" above, during the year ended December 31, 2002, the Company repurchased $47.1 million of its 9-5/8 percent senior notes, $13.9 million of its 8-7/8 percent senior notes and repaid a $45.2 million West Panhandle gas field capital cost obligation. Additionally, during the year ended December 31, 2001, the Company redeemed its remaining 11-5/8 percent and 10-5/8 percent senior subordinated notes and $38.7 million of its 9-5/8 percent senior notes.

At December 31, 2002, the Company had a $575.0 million corporate credit facility with a syndicate of banks that matures on March 1, 2005. Outstanding borrowings under the corporate credit facility totaled $260.0 million as of December 31, 2002. In addition, the Company has five outstanding senior note issuances at December 31, 2002. Such debt issuances consist of (i) $136.1 million aggregate principal amount of 8-7/8 percent senior notes due in 2005; (ii) $150 million aggregate principal amount of 8-1/4 percent senior notes due in 2007; (iii) $350 million aggregate principal amount of 6-1/2 percent senior notes due in 2008; (iv) $339.2 million aggregate remaining principal amount of 9-5/8 percent senior notes due in 2010; (v) $150 million aggregate principal amount of 7-1/2 percent senior notes due in 2012; and (vi) $250 million aggregate principal amount of 7-1/5 percent senior notes due in 2028. Certain of the obligations above contain restrictive covenants, each of which the Company is in compliance.

The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2002 was 5.74 percent as compared to 7.52 percent for the year ended December 31, 2001 and 8.68 percent for the year ended December 31, 2000, taking into account the effect of interest rate swaps. See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more specific information regarding the Company's long-term debt as of December 31, 2002 and 2001.

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 Company's Board of Directors.

Sales of non-strategic assets. During 2002, 2001 and 2000, proceeds from the sale of non-strategic assets totaled $118.9 million, $113.5 million and $102.7 million, respectively. The Company's 2002, 2001 and 2000 asset divestitures were comprised of hedge derivatives, common stock of a non-affiliated entity, and non-strategic United States and Canadian oil and gas properties, gas plants and other assets. The cash proceeds received from asset divestitures during 2002 and 2001 were used to fund a portion of the Company's 2002 and 2001 capital expenditures and for general corporate obligations. The net cash proceeds from the 2000 asset divestitures were used to reduce the Company's outstanding indebtedness (see "Results of Operations", above, and Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data").

Book capitalization and liquidity. The Company's total debt was $1.67 billion as of December 31, 2002, as compared to total debt of $1.58 billion on December 31, 2001 and 2000. The Company's total book capitalization at December 31, 2002 was $3.04 billion, consisting of total debt of $1.67 billion and stockholders' equity of $1.37 billion. The Company's debt to total capitalization was 55 percent at December 31, 2002. The Company's ratio of current assets to current liabilities was .54 at December 31, 2002 and 1.12 at December 31, 2001. The decline in the Company's ratio of current assets to current liabilities was primarily due to a $170.7 million difference in the fair value of 2003 maturing derivatives at December 31, 2002 as compared to the fair value of 2002 maturing derivatives at December 31, 2001. Including $27.2 million of undrawn and outstanding letters of credit, the Company has $287.8 million of unused borrowing capacity available under its Credit Agreement as of December 31, 2002.

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, 2002 and 2001, 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 that the Company is a party to do 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 are determined based on counterparties' estimates and valuation models. The Company has not changed its valuation method during 2002. During 2002, the Company was a party to forward foreign exchange contracts, commodity and interest 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 2002:

	Derivative Contract Assets (Liabilities)			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2001	$ 180,554	$ (19,637)	$ 61	$ 160,978
Changes in contract fair values (1)	(183,285)	62,786	203	(120,296)
Contract realizations:				
Maturities	(48,212)	(11,155)	(249)	(59,616)
Termination - cash settlements	(58,685)	(31,994)	-	(90,679)
Termination - future obligations	1,303	-	-	1,303
Termination - future receivables	(479)	-	-	(479)
Fair value of contracts outstanding as of December 31, 2002	$(108,804)	$ -	$ 15	$(108,789)

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

</FN>

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information, in U. S. dollar equivalent amounts, about other financial instruments that the Company was a party to as of December 31, 2002 and 2001 and that are or were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates together with the weighted average interest rates expected to be paid on the debt, given current contractual terms and market conditions. 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, 2002 and 2001. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curves for the six-month London Interbank Offered Rate.

Interest Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2002 (1)

	2003	2004	2005	2006	2007	Thereafter	Total	Liability Fair Value
			(in thousands except interest rates)					
Total Debt:								
U.S. dollar denominated maturities:								
Fixed rate debt	$ -	$ -	$146,704	$ -	$161,130	$1,100,702	$1,408,536	$(1,484,009)
Weighted average interest rate (%)	7.94	7.94	7.87	7.83	7.81	7.77		
Variable rate debt	$ -	$ -	$260,000	$ -	$ -	$ -	$ 260,000	$ (260,000)
Average interest rate (%)	2.89	4.08	5.27					

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(1) During February 2003, the Company entered into interest rate swap contracts to hedge a portion of the fair value of its 9-5/8 percent senior notes. Under the terms of the interest rate swap contracts, the Company will receive a fixed annual rate of 9-5/8 percent on $250 million notional amount and will pay the counterparties a variable rate on the notional amount equal to the six-month LIBOR, reset semi- annually, plus a weighted average margin of 566.4 basis points.

</FN>

The accompanying Interest Rate Sensitivity table as of December 31, 2001 also provides information about interest rate swap agreements that the Company was a party to as of that date. These interest rate swap agreements were terminated during the year ended December 31, 2002 and no longer represent market risk to the Company. The interest rate swap agreements as of December 31, 2001 hedged (i) the fair value of the Company's 8-1/4 percent senior notes; (ii) the fair value of the Company's 6-1/2 percent senior notes; and (iii) a portion of the interest rate risk associated with the Company's Credit Agreement.

Interest Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2001

	2002	2003	2004	2005	2006	Thereafter	Total	Liability Fair Value
	(in thousands except interest rates)							
Total Debt:								
U.S. dollar denominated maturities:								
Fixed rate debt...........	$ -	$ -	$ -	$161,998	$ -	$1,121,306	$1,283,304	$(1,268,178)
Weighted average interest rate (%)........	8.06	8.06	8.06	7.98	7.95	7.95		
Variable rate debt.........	$ -	$ -	$ -	$294,000	$ -	$ -	$ 294,000	$ (294,000)
Average interest rates (%).	4.38	6.12	6.90	7.27				
Interest Rate Hedge Derivatives:								
8-1/4% senior notes hedge:								
Notional debt amount.......	$150,000	$150,000	$150,000	$150,000	$150,000	$ 150,000	$ 150,000	$ (2,965)
Fixed rate receivable (%)..	8.25	8.25	8.25	8.25	8.25	8.25		
Variable rate payable (%)..	6.50	8.24	9.02	9.39	9.64	9.79		
6-1/2% senior notes hedge:								
Notional debt amount.......	$350,000	$350,000	$350,000	$350,000	$350,000	$ 350,000	$ 350,000	$ (16,229)
Fixed rate receivable (%)..	6.50	6.50	6.50	6.50	6.50	6.50		
Variable rate payable (%)..	5.15	6.89	7.67	8.04	8.29	8.44		
Credit Agreement hedge:								
Notional debt amount.......	$ 55,000						$ 55,000	$ (443)
Fixed rate payable (%).....	5.43							
Variable rate receivable (%)..........	4.38							

Foreign exchange rate sensitivity. The following tables provide information, in U.S. dollar equivalent amounts, about derivative financial instruments that the Company was a party to as of December 31, 2002 and 2001 and that were sensitive to changes in foreign exchange rates.

Foreign Exchange Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2002

	2003	Total	Asset Fair Value (1)
	(in thousands except interest rates)		
Foreign Exchange Rate Hedge Derivatives:			
Notional amount of foreign currency forward contracts....................	$ 2,000	$ 2,000	$ 15
Fixed Canadian to U.S. dollar rate paid........	.6258		

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(1) The Company's foreign currency forward contract matured as a $15 thousand asset during January 2003.
</FN>

Foreign Exchange Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2001

	2002	Total	Asset Fair Value
	(in thousands except interest rates)		
Foreign Exchange Rate Hedge Derivatives:			
Notional amount of foreign currency forward contracts....................	$ 24,752	$ 24,752	$ 61
Fixed Canadian to U.S. dollar rate paid........	.6266		
Average forward Canadian dollar to U.S. dollar exchange rate as of February 28, 2002.........	.6250		

Commodity price sensitivity. The following tables provide information, in U.S. dollar equivalent amounts, about derivative financial instruments that the Company was a party to as of December 31, 2002 and 2001 and that were sensitive to changes in oil and gas prices. As of December 31, 2002 and 2001, all of the Company's derivative financial instruments that were sensitive to changes in oil and gas prices qualified as hedges.

Commodity hedge instruments. The Company hedges commodity price risk with 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, C 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 and gas prices.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2002

	2003	2004	Liability Fair Value
Oil Hedge Derivatives (1):			
Average daily notional Bbl volumes:			
Swap contracts (2)............................	22,236	14,000	$ (19,912)
Weighted average fixed price per Bbl.........	$ 24.45	$ 23.11	
Average forward NYMEX oil prices per Bbl (3)....	$ 31.55	$ 25.75	

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(1) 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 for 2003 and 2004.

(2) During January 2003, the Company increased its 2003 oil hedge positions by entering into 6,000 Bbls per day of March 2003 oil swap contracts with average per Bbl fixed prices of $33.51.

(3) The average forward NYMEX oil prices per Bbl are based on February 18, 2003 market quotes.

</FN>

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2001

	2002	2003	Asset Fair Value
Oil Hedge Derivatives (1):			
Average daily notional Bbl volumes:			
Swap contracts..................................	9,463	2,975	$ 23,423
Weighted average fixed price per Bbl...........	$ 26.23	$ 24.02	
Collar contracts...............................	2,975		$ 5,506
Weighted average short call ceiling price per Bbl....................................	$ 28.61		
Weighted average long put floor price per Bbl....................................	$ 25.00		
Average forward NYMEX oil prices (1).............	$ 21.86	$ 21.54	

<FN>

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(1) The average forward NYMEX oil prices are based on February 28, 2002 market quotes.

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Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2002

	2003	2004	2005	2006 & 2007	Liability Fair Value
Gas Hedge Derivatives (1) (2):					
Average daily notional MMBtu volumes:					
Swap contracts..................................	230,000	180,000	10,000	20,000	$ (88,892)
Weighted average fixed price per MMBtu..........	$ 3.76	$ 3.81	$ 3.70	$ 3.75	
Average forward NYMEX gas prices per MMBtu (3).....	$ 5.53	$ 4.80	$ 4.31	$ 4.12	

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(1) 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 option contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(2) 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 per MMBtu by calendar quarter for 2003, 2004, 2005, 2006 and 2007.

(3) The average forward NYMEX gas prices per MMBtu are based on February 18, 2003 market quotes.

</FN>

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2001

	2002	2003	2004	2005	Asset Fair Value
Gas Hedge Derivatives (1) (2):					
Average daily notional MMBtu volumes:					
Swap contracts..................................	165,205	117,500	165,000	50,000	$ 137,606
Weighted average fixed price per MMBtu.........	$ 4.19	$ 3.62	$ 3.84	$ 3.63	
Collar contracts...............................	20,000				$ 14,019
Weighted average short call ceiling price per MMBtu..................................	$ 6.00				
Weighted average long put floor price per MMBtu..................................	$ 4.50				
Average forward NYMEX gas prices per MMBtu (2)....	$ 2.68	$ 3.21	$ 3.42	$ 3.52	

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(1) 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 option contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(2) The average forward NYMEX gas prices per MMBtu are based on February 28, 2002 market quotes.

</FN>

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. To realize its objectives, the Company borrows under fixed and variable rate debt instruments, based on the availability of capital, market conditions and hedge opportunities. See Note E 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 has, from time to time, entered into 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 Company's board of directors. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of hedge transactions. Although the Company is a party to certain derivative contracts that do not qualify for hedge accounting treatment, the Company's policy is to limit its participation in derivative contracts to those that, in the opinion of management, reduce the Company's overall economic risk.

As of December 31, 2002, the Company's primary risk exposures associated with financial instruments to which it is a party include oil and gas price volatility, volatility in the exchange rates of the Canadian dollar and Argentine peso vis a vis the U.S. dollar and interest rate volatility. The Company's primary risk exposures associated with financial instruments have not changed significantly since December 31, 2002.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Shareholders
Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2002. 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 auditing standards generally accepted in the 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, 2002 and 2001, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note B to the consolidated financial statements, in 2001 Pioneer Natural Resources Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities".

Ernst & Young LLP

Dallas, Texas
January 24, 2003

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

ASSETS

	December 31, 2002	December 31, 2001
Current assets:		
Cash and cash equivalents	$ 8,490	$ 14,334
Accounts receivable:		
Trade, net of reserves for doubtful accounts of $4,744 and $5,553 as of December 31, 2002 and 2001, respectively	97,774	81,616
Affiliates	448	595
Inventories	10,648	14,549
Deferred income taxes	13,900	6,400
Other current assets:		
Derivative assets, net of valuation reserves of $3,351 and $3,153 as of December 31, 2002 and 2001, respectively	3,150	127,074
Other	12,683	11,075
Total current assets	147,093	255,643
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	4,252,897	3,691,783
Unproved properties	219,073	187,785
Accumulated depletion, depreciation and amortization	(1,303,541)	(1,095,310)
	3,168,429	2,784,258
Deferred income taxes	76,840	84,319
Other property and equipment, net	22,784	21,560
Other assets, net:		
Derivative assets, net of valuation reserves of $1,136 and $1,069 as of December 31, 2002 and 2001, respectively	793	54,486

Other	39,177	70,787
	$ 3,455,116	$ 3,271,053

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:		
Accounts payable:		
Trade	$ 117,582	$ 92,760
Affiliates	7,192	6,405
Interest payable	37,458	37,410
Other current liabilities:		
Derivative obligations	83,638	36,830
Other	28,722	54,804
Total current liabilities	274,592	228,209
Long-term debt	1,668,536	1,577,304
Noncurrent derivative obligations	42,490	32,438
Other noncurrent liabilities	85,841	133,945
Deferred income taxes	8,760	13,768
Stockholders' equity:		
Preferred stock, $.01 par value; 100,000,000 shares authorized; zero and one share issued and outstanding as of December 31, 2002 and 2001, respectively	-	-
Common stock, $.01 par value; 500,000,000 shares authorized; 119,592,344 shares issued at December 31, 2002; and 107,422,467 shares issued at December 31, 2001	1,196	1,074
Additional paid-in capital	2,714,567	2,462,272
Treasury stock, at cost; 2,339,806 shares at December 31, 2002 and 3,486,073 shares at December 31, 2001	(32,219)	(48,002)
Deferred compensation	(14,292)	-
Accumulated deficit	(1,298,440)	(1,323,343)
Accumulated other comprehensive income:		
Deferred hedge gains, net	9,555	201,046
Cumulative translation adjustment	(5,470)	(7,658)
Total stockholders' equity	1,374,897	1,285,389
Commitments and contingencies		
	$ 3,455,116	$ 3,271,053

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,		
	2002	2001	2000
Revenues and other income:			
Oil and gas	$ 701,780	$ 847,022	$ 852,738
Interest and other	11,222	21,778	25,775
Gain on disposition of assets, net	4,432	7,681	34,184
	717,434	876,481	912,697
Costs and expenses:			
Oil and gas production	199,570	209,664	189,265
Depletion, depreciation and amortization	216,375	222,632	214,938
Exploration and abandonments	85,894	127,906	87,550
General and administrative	48,402	36,968	33,262

Interest	95,815	131,958	161,952
Other	17,256	39,588	67,231
	663,312	768,716	754,198
Income before income taxes and extraordinary items	54,122	107,765	158,499
Income tax benefit (provision)	(5,063)	(4,016)	6,000
Income before extraordinary items	49,059	103,749	164,499
Extraordinary items - loss on early extinguishment of debt, net of tax	(22,346)	(3,753)	(12,318)
Net income	$ 26,713	$ 99,996	$ 152,181
Income per share:			
Basic:			
Income before extraordinary items	$ .44	$ 1.05	$ 1.65
Extraordinary items	(.20)	(.04)	(.12)
Net income	$ .24	$ 1.01	$ 1.53
Diluted:			
Income before extraordinary items	$ .43	$ 1.04	$ 1.65
Extraordinary items	(.20)	(.04)	(.12)
Net income	$ .23	$ 1.00	$ 1.53
Weighted average shares outstanding:			
Basic	112,542	98,529	99,378
Diluted	114,288	99,714	99,763

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

						Accumulated Other Comprehensive Income			
	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compen-sation	Accumulated Deficit	Deferred Hedge Gains & Losses	Invest-ment Gains & Losses	Trans-lation Adjustment	Total Stock-holders' Equity
Balance at December 31, 1999	$ 1,009	$2,348,448	$(10,384)	$ -	$(1,574,884)	$ -	$ -	$ 10,425	$ 774,614
Exercise of stock options and employee stock purchases	4	4,160	-	-	-	-	-	-	4,164
Purchase of treasury stock	-	-	(27,298)	-	-	-	-	-	(27,298)
Net income	-	-	-	-	152,181	-	-	-	152,181
Other comprehensive income (loss):									
Unrealized gains on available for sale securities:									
Unrealized holdings gains	-	-	-	-	-	-	33,828	-	33,828
Gains included in net income	-	-	-	-	-	-	(25,674)	-	(25,674)
Currency translation adjustment	-	-	-	-	-	-	-	(6,910)	(6,910)
Balance at December 31, 2000	1,013	2,352,608	(37,682)	-	(1,422,703)	-	8,154	3,515	904,905
Common stock issued for partnership acquisitions	57	104,236	-	-	-	-	-	-	104,293
Exercise of stock options and employee stock purchases	4	5,428	2,708	-	(636)	-	-	-	7,504
Purchase of treasury stock	-	-	(13,028)	-	-	-	-	-	(13,028)
Net income	-	-	-	-	99,996	-	-	-	99,996
Other comprehensive income (loss):									
Deferred hedge gains and losses:									
Transition adjustment	-	-	-	-	-	(197,444)	-	-	(197,444)
Deferred hedge gains	-	-	-	-	-	393,004	-	-	393,004
Net losses included in net income	-	-	-	-	-	5,486	-	-	5,486
Unrealized gains and losses on									

available for sale securities:									
Unrealized holdings losses...	-	-	-	-	-	-	(45)	-	(45)
Gains included in net income.	-	-	-	-	-	-	(8,109)	-	(8,109)
Currency translation adjustment.	-	-	-	-	-	-	-	(11,173)	(11,173)
Balance at December 31, 2001......	1,074	2,462,272	(48,002)	-	(1,323,343)	201,046	-	(7,658)	1,285,389
Issuance of common stock..........	115	235,885	-	-	-	-	-	-	236,000
Adjustment to common stock issued for 2001 partnership acquisitions....................	-	(175)	-	-	-	-	-	-	(175)
Exercise of stock options and employee stock purchases.........	-	416	15,783	-	(1,810)	-	-	-	14,389
Deferred compensation:									
Compensation deferred...........	7	16,169	-	(16,176)	-	-	-	-	-
Deferred compensation included in net income..................	-	-	-	1,884	-	-	-	-	1,884
Net income........................	-	-	-	-	26,713	-	-	-	26,713
Other comprehensive income (loss):									
Deferred hedge gains and losses, net of tax:									
Deferred hedge losses........	-	-	-	-	-	(179,067)	-	-	(179,067)
Net gains included in net income......................	-	-	-	-	-	(12,424)	-	-	(12,424)
Currency translation adjustment.	-	-	-	-	-	-	-	2,188	2,188
Balance at December 31, 2002......	$ 1,196	$2,714,567	$(32,219)	$(14,292)	$(1,298,440)	$ 9,555	$ -	$ (5,470)	$1,374,897

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, 2002	2001	2000
Cash flows from operating activities:			
Net income...	$ 26,713	$ 99,996	$ 152,181
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization...............	216,375	222,632	214,938
Exploration expenses, including dry holes.............	64,617	103,595	66,959
Deferred income taxes..................................	2,788	(7,649)	(10,600)
Gain on disposition of assets, net.....................	(4,432)	(7,681)	(34,184)
Loss on early extinguishment of debt, net of tax.......	22,346	3,753	12,318
Interest related amortization..........................	(5,809)	8,689	12,699
Commodity hedge related amortization..................	26,490	6,199	-
Other noncash items....................................	9,301	14,944	59,776
Change in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable....................................	(23,922)	41,295	(7,486)
Inventory..	3,023	(4,256)	(2,789)
Other current assets...................................	(1,836)	(6,304)	(9,896)
Accounts payable.......................................	(342)	(541)	26,260
Interest payable.......................................	48	(733)	2,097
Other current liabilities..............................	(3,115)	1,661	(52,177)
Net cash provided by operating activities.............	332,245	475,600	430,096
Cash flows from investing activities:			
Cash acquired in acquisitions, net of fees paid............	-	11,119	-
Proceeds from disposition of assets........................	118,850	113,453	102,736
Additions to oil and gas properties........................	(614,698)	(529,723)	(299,682)
Other property dispositions (additions), net...............	(12,283)	(17,590)	2,445
Net cash used in investing activities.................	(508,131)	(422,741)	(194,501)
Cash flows from financing activities:			
Borrowings under long-term debt............................	529,805	328,331	922,607
Principal payments on long-term debt.......................	(481,783)	(333,410)	(1,099,935)

Common stock issuance proceeds, net of issuance costs	236,000	-	-
Payments of other noncurrent liabilities	(124,245)	(53,437)	(29,759)
Exercise of stock options and employee stock purchases	14,389	7,504	4,164
Purchase of treasury stock	-	(13,028)	(27,298)
Deferred loan fees/issuance costs	(3,293)	-	(13,847)
Net cash provided by (used in) financing activities	170,873	(64,040)	(244,068)
Net decrease in cash and cash equivalents	(5,013)	(11,181)	(8,473)
Effect of exchange rate changes on cash and cash equivalents	(831)	(644)	(156)
Cash and cash equivalents, beginning of year	14,334	26,159	34,788
Cash and cash equivalents, end of year	$ 8,490	$ 14,334	$ 26,159

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year ended December 31,		
	2002	2001	2000
Net income	$ 26,713	$ 99,996	$ 152,181
Other comprehensive income (loss):			
Deferred hedge gains and losses, net of tax:			
Transition adjustment	-	(197,444)	-
Deferred hedge gains (losses)	(179,067)	393,004	-
Net (gains) losses included in net income	(12,424)	5,486	-
Gains and losses on available for sale securities:			
Unrealized holding gains (losses)	-	(45)	33,828
Gains included in net income	-	(8,109)	(25,674)
Currency translation adjustment	2,188	(11,173)	(6,910)
Other comprehensive income (loss)	(189,303)	181,719	1,244
Comprehensive income (loss)	$ (162,590)	$ 281,715	$ 153,425

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

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company (the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, Argentina, Canada, South Africa, Gabon 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 subsidiaries since their acquisition or formation, and the Company's interest in the affiliated oil and gas partnerships for which it serves as general partner through certain of its wholly-owned subsidiaries. The Company proportionately consolidates less than 100 percent-owned oil and gas partnerships in accordance with industry practice. The Company owns less than a 20 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Investments in non-affiliated equity securities that have a readily determinable fair value are classified as "trading securities" if management's current intent is to hold them for only a short period of time; otherwise, they are accounted for as "available-for-sale" securities. The Company reevaluates the classification of investments in non-affiliated 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 revenue, and unrealized holding losses are recognized in other expense during the periods in which changes in fair value occur. As of December 31, 2002, the Company had $.2 million of trading securities recorded to other assets. The Company had no investments in trading securities as of December 31, 2001.

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 did not have any investments in available-for-sale securities as of December 31, 2002 or 2001.

Investments in non-affiliated 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 did not have any equity security investments that did not have a readily determinable fair value as of December 31, 2002 or 2001.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties 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.

Early in January 2002, the Argentine government severed the direct one-to-one U.S. dollar to Argentine peso relationship that had existed for many years. The following bullet points disclose the significant Argentine assumptions utilized in the preparation of the 2002 and 2001 financial statements:

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

- As of December 31, 2002 and 2001, the Company used exchange rates of 3.37 pesos to $1 and 1.7 pesos to $1, respectively, to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries.

- As part of the December 31, 2001 remeasurement process, the Company estimated that the recovery or settlement values to be realized on pre-devaluation, peso-denominated receivables and payables would be approximately 1.2 pesos to $1.

- After remeasuring inventory at historical exchange rates, the Company reduced the carrying value of its Argentine lease and well equipment to market values. The market value of the inventory was estimated to be 15 percent higher than the historical peso balance, but lower than the Company's carrying cost on an equivalent U.S. dollar basis as of December 31, 2001.

- The Company reviewed its Argentine proved and unproved properties for impairment as of December 31, 2002 and 2001. The Company's assessments were based on the Company's expectations of future commodity prices to be received and expenses to be paid in Argentina. The December 31, 2002 assumptions utilized to determine future net cash flows had oil and natural gas liquids ("NGLs") prices at world market prices adjusted for export taxes and local market discounts. Gas prices were assumed to return to predevaluation U.S. dollar levels after a period of time to allow for inflation. Expenses were initially assumed to be equivalent to reported expenses in 2002, but to gradually increase to 15 percent above 2002 levels. Based upon these assumptions, the Company determined that the carrying value of its proved and unproved properties was fully recoverable.

The remeasurement of the peso-denominated monetary net assets of the Company's Argentine subsidiaries as of December 31, 2002 resulted in the Company recognizing a $6.9 million charge during 2002. The December 31, 2001 remeasurement of the Company's Argentine subsidiaries' peso-denominated monetary net assets and the adjustment to reduce the subsidiaries' carrying values of lease and well equipment inventory to market values resulted in the Company recognizing a $7.7 million charge in 2001. Numerous uncertainties exist surrounding the ultimate resolution of Argentina's economic and political instability and actual results could differ from those estimates and assumptions utilized.

The Argentine economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, (i) the realized prices the Company receives for the commodities it produces and sells; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities.

New accounting pronouncements. During June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amends Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19") to require 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 capitalized as part of the carrying value of the long-lived asset. Under the provisions of SFAS 19, asset retirement obligations are recognized using a cost-accumulation approach. The Company currently records significant asset retirement obligations through the unit-of-production method, except for such liabilities that were assumed in business combinations, which were recorded at their estimated fair values. The Company adopted the provisions of SFAS 143 on

January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $13.8 million increase in the carrying values of proved properties, (ii) a $26.3 million decrease in accumulated depreciation, depletion,

and amortization of property, plant and equipment, (iii) a $1.0 million increase in current abandonment liabilities and (iv) a $22.4 million increase in noncurrent abandonment liabilities. The net impact of items (i) through (iv) was to record a gain of $16.7 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003.

During April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. The Company adopted the provisions of SFAS 145 on January 1, 2003. The adoption of the provisions of SFAS 145 is not expected to affect the Company's future financial position or liquidity. Upon adoption of the provisions of SFAS 145, gains or losses from the early extinguishment of debt recognized in the Company's consolidated statements of operations for the years ended December 31, 2002, 2001 and 2000 will be reclassified to other revenues or other expense and included in the determination of the income (loss) from continuing operations of those periods.

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

Inventories - equipment. Lease and well equipment to be used in future production and drilling activities are carried at the lower of cost or market, on a first-in, first-out basis. The Company has established lower of cost or market allowances to reduce the carrying values of its equipment inventories in the amounts of $3.6 million and $6.8 million as of December 31, 2002 and 2001, respectively.

Inventories - commodities. Commodities are carried at the lower of average cost or market. When sold from inventory, commodities are removed on a first-in, first-out basis.

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 also expenses the costs associated with exploratory wells that find oil and gas reserves if a determination that proved reserves have been found cannot be made within one year of the exploration well being drilled. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use.

The Company owns interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. The Company's ownership 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. The third party revenues generated from the plant and treating facilities for the three years ended December 31, 2002, 2001 and 2000 were $28.4 million, $32.7 million and $36.3 million, respectively. The third party expenses attributable to the plants and treating facilities for those same periods were $9.3 million, $9.7 million and $9.0 million, respectively. 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.

Capitalized costs of individual properties sold or abandoned are charged to accumulated depletion, depreciation and amortization with the proceeds from the sales of individual properties credited to property costs. 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 amortization base.

If significant, the Company accrues the estimated future costs to plug and abandon wells under the unit-of-production method. The charge, if any, is reflected in the accompanying Consolidated Statements of Operations as abandonment expense while the liability is reflected in the accompanying Consolidated Balance Sheets as other liabilities. Plugging and abandonment liabilities assumed in a business combination accounted for as a purchase are recorded at fair value. At December 31, 2002 and 2001, the Company has recognized plugging and abandonment liabilities of $34.7 million and $39.5 million, respectively. See "New accounting pronouncements" for a discussion of the provisions of SFAS 143 that will be adopted by the Company on January 1, 2003.

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 that are individually significant are periodically assessed for impairment by comparing their cost to their estimated value on a project-by-project basis. The estimated value 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 by recording an allowance. The remaining unproved oil and gas properties, if any, are aggregated and an overall impairment allowance is provided based on the Company's historical experience.

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.

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 are fixed or reliably determinable.

Revenue recognition. The Company uses the entitlements method of accounting for oil, NGL and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying Consolidated Balance Sheets. The following table presents the Company's entitlement assets and entitlement liabilities and their associated volumes as of December 31, 2002 and 2001 (in millions):

	December 31,			
	2002		2001	
	Amount	MMcf	Amount	MMcf
Entitlement assets	$ 9.7	4,240	$ 30.9	25,335
Entitlement liabilities	$ 15.1	14,302	$ 20.3	15,197

Derivatives and hedging. Prior to January 1, 2001, the following criteria were required to be met in order for the Company to account for a derivative instrument as a hedge of an existing asset or liability, or of a forecasted transaction: an asset, liability or forecasted transaction must have existed that exposed the Company to price, interest rate or foreign exchange rate risk that was not offset in another asset or liability; the derivative instrument must have reduced that price, interest rate or foreign exchange rate risk; and, the derivative instrument must have been designated as a hedge at the inception of the instrument and throughout the hedge period. Additionally, in order to qualify as a hedge, there must have been clear correlation between changes in the fair value or expected cash flows of the derivative instrument and the fair value or expected cash flows of the hedged asset or liability, or forecasted transaction, such that changes in the derivative instrument offset the effect of price, interest rate or foreign exchange rate changes on the exposed items.

Prior to January 1, 2001, gains or losses realized from derivative instruments that qualified as hedges were deferred as assets or liabilities until the underlying hedged asset, liability or transaction monetized, matured or was otherwise recognized under generally accepted accounting principles. When recognized in net income (loss), hedge gains and losses were classified as components of the commodity prices, interest or foreign exchange rates that the derivative instrument hedged. Derivative instruments that were not hedges were recorded at fair value, as assets or liabilities. Changes in the fair values of non-hedge derivative instruments were recognized as other income or other expense during the periods in which their fair values changed.

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") as amended, the provisions of which the Company adopted effective January 1, 2001.

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 (loss). 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 (loss). Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in Accumulated other comprehensive income ("AOCI") - deferred hedge gains, net in the stockholders' equity section of the Company's Consolidated Balance Sheets until such time as the hedged items are recognized in net income (loss). Ineffective portions of a derivative instrument's change in fair value are immediately recognized in net income (loss).

The adoption of SFAS 133 resulted in a January 1, 2001 transition adjustment to (i) reclassify $57.8 million of deferred losses on terminated hedge positions from other assets (including $11.6 million of other current assets), (ii) increase other current assets, other assets and other current liabilities by $7.0 million, $6.2 million and $146.6 million, respectively, to record the fair value of open hedge derivatives, (iii) increase the carrying value of hedged long-term debt by $6.2 million and (iv) reduce stockholders' equity by $197.4 million for the net impact of items (i) through (iii) above. The $197.4 million reduction in stockholders' equity was reflected as a transition adjustment in other comprehensive income (loss) on January 1, 2001.

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 actual hedge effectiveness at the end of each calendar quarter.

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

Stock-based compensation. The Company has a long-term incentive plan (the "Long-Term Incentive Plan") under which the Company grants stock-based compensation. The Long-Term Incentive Plan is described more fully in Note G. The Company accounts for stock-based compensation granted under the Long-Term Incentive Plan using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") and related interpretations. Stock-based compensation expenses were not recognized in net income, as all options granted under the Long-Term Incentive Plan had exercise prices equal to the market value of the underlying common stock on the dates of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123") to stock-based employee compensation:

	Year ended December 31,		
	2003	2002	2001

	(in thousands, except per share amounts)		
Net income, as reported	$ 26,713	$ 99,996	$152,181
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(9,807)	(6,533)	(4,163)
Pro forma net income	$ 16,906	$ 93,463	$148,018
Net income per share:			
Basic - as reported	$ .24	$ 1.01	$ 1.53
Basic - pro forma	$ .15	$ .95	$ 1.49
Diluted - as reported	$ .23	$ 1.00	$ 1.53
Diluted - pro forma	$ .15	$ .94	$ 1.48

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

The functional currency of the Company's Canadian operations is the Canadian dollar. The financial statements of the Company's Canadian subsidiary entities are translated to U. S. dollars as follows: all assets and liabilities are translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses are 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 are

recorded in the accompanying Consolidated Statements of Stockholders' Equity for the period through accumulated other comprehensive income (loss).

The exchange rates used to translate the financial statements of the Company's Canadian subsidiary in the preparation of these consolidated financial statements appear below:

	December 31,		
	2002	2001	2000
Translation:			
U.S. Dollar from Canadian Dollar - Balance Sheets	.6362	.6277	.6671
U.S. Dollar from Canadian Dollar - Statements of Operations	.6371	.6356	.6650

Reclassifications. Certain reclassifications have been made to the 2001 and 2000 amounts to conform to the 2002 presentation.

NOTE C. 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, 2002 and 2001:

	2002		2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Derivative contract assets (liabilities):				
Commodity price hedges....................	$(108,837)	$(108,837)	$ 151,290	$ 151,290
Btu swap contracts........................	$ (13,363)	$ (13,363)	$ (19,422)	$ (19,422)
Interest rate swaps.......................	$ -	$ -	$ (19,637)	$ (19,637)
Foreign currency contracts................	$ 15	$ 15	$ 61	$ 61
Financial assets:				
Trading securities........................	$ 236	$ 236	$ -	$ -
5-1/2% note receivable due 2008...........	$ 2,247	$ 2,283	$ -	$ -
Financial liabilities - long-term debt:				
Line of credit............................	$(260,000)	$(260,000)	$(294,000)	$(294,000)
8-7/8% senior notes due 2005..............	$(146,704)	$(147,318)	$(161,998)	$(159,000)
8-1/4% senior notes due 2007..............	$(161,130)	$(164,925)	$(153,672)	$(154,215)
6-1/2% senior notes due 2008..............	$(362,592)	$(359,205)	$(332,613)	$(329,280)
9-5/8% senior notes due 2010..............	$(338,197)	$(406,901)	$(385,110)	$(421,508)
7-1/2% senior notes due 2012..............	$(150,000)	$(160,635)	$ -	$ -
7-1/5% senior notes due 2028..............	$(249,913)	$(245,025)	$(249,911)	$(204,175)

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. During the year ended December 31, 2002, the Company terminated all of its interest rate swaps and the Company's foreign currency contracts matured. See Note J for a description of each of these derivatives, including whether the derivative contract qualifies for hedge accounting treatment or is considered a speculative derivative contract.

Financial assets. As of December 31, 2002, the Company had an investment in bonds that were classified as trading securities and a note receivable. The Company divested the bonds during January 2003. The fair value of the 5-1/2 percent note receivable was determined based on underlying market rates of interest.

Long-term debt. The carrying amount of borrowings outstanding under the Company's corporate 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 E for additional information regarding the Company's long-term debt.

NOTE D. Acquisitions

Falcon acquisitions. During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest in and operates the Falcon field development and related exploration blocks.

West Panhandle acquisitions. During July 2002, the Company completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded $100.4 million to proved oil and gas properties, $3.8 million to unproved oil and gas properties and $1.9 million to assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash. The capital cost obligation retired by the Company for $60.8 million represented an obligation for West Panhandle gas field capital additions that was not able to be prepaid and bore interest at an annual rate of 20 percent. The portion of the purchase price allocated to the retirement of the capital cost obligation was based on a discounted cash flow analysis using a market discount rate for obligations with similar terms. The capital cost obligation had a carrying value of $45.2 million, resulting in an extraordinary loss of $15.6 million from the early extinguishment of this obligation.

Affiliated partnership mergers. During 2001, the limited partners of 42 of the Company's affiliated partnerships approved an agreement and plan of merger ("Plan of Merger") among the Company, Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of the Company, and the partnerships. The Plan of Merger was accounted for as a purchase business combination. In consideration for the partnerships' net assets, the limited partners received 5.7 million shares of the Company's common stock valued at $18.35 per share. In connection with this transaction, the Company recorded $92.9 million to proved oil and gas properties, $13.6 million to cash and $.3 million to other net assets. The cash acquired from the partnerships, net of $2.5 million of cash transaction costs, is included in "cash acquired in acquisitions, net of fees paid" in the accompanying Consolidated Statement of Cash Flows for the year ended December 31, 2001. Except for the cash acquired, this transaction represents a noncash investing activity of the Company that was funded by the issuance of common stock.

During 2000, the Company received the approval of the partners of 13 employee partnerships to merge with Pioneer USA for a purchase price of $2.0 million. Of the total purchase price, $317 thousand was paid to Company employees. Additionally, during 2000, the Company purchased all of the direct oil and gas interests held by the Company's Chairman of the Board and Chief Executive Officer for $195 thousand.

Other acquisitions. During the year ended December 31, 2002, in addition to the Falcon and West Panhandle acquisitions referred to above, the Company spent approximately $25.5 million to acquire additional unproved acreage in the United States, including 34 Gulf of Mexico shelf blocks, six deepwater Gulf of Mexico blocks, a 70 percent

working interest in ten state leases on Alaska's North Slope and property interests in other areas of the United States. Also during 2002, the Company acquired unproved and proved oil and gas property interests in Canada for 2.3 million and $.5 million, respectively, and $1.8 million of additional unproved property interests in Tunisia. During 2001, the Company spent $77.9 million to acquire additional working interests in the United States Gulf of Mexico Aconcagua discovery, the related Canyon Express gathering system and the Devils Tower project; 21 deepwater Gulf of Mexico blocks; 250,000 acres in the Anticlinal Campamento, Dos Hermanas and La Calera areas of the Neuquen Basin in Argentina; and a 30 percent interest in the Anaguid permit in the Ghadames basin onshore Southern Tunisia. During 2000, the Company spent $65.0 million to acquire additional working interests in the United States Gulf of Mexico discovery at Devils Tower and the Chinchaga gas field in Canada, an interest in the Camden Hills deepwater Gulf of Mexico discovery and the Canyon Express gathering system.

NOTE E. Long-term Debt

Long-term debt, including the effects of fair value hedges and discounts, consisted of the following components at December 31, 2002 and 2001:

	December 31, 2002	December 31, 2001
	(in thousands)	
Line of credit..............................	$ 260,000	$ 294,000
8-7/8% senior notes due 2005................	146,704	161,998
8-1/4% senior notes due 2007................	161,130	153,672
6-1/2% senior notes due 2008................	362,592	332,613
9-5/8% senior notes due 2010................	338,197	385,110
7-1/2% senior notes due 2012................	150,000	-
7-1/5% senior notes due 2028................	249,913	249,911
	$1,668,536	$1,577,304

Maturities of long-term debt at December 31, 2002 are as follows (in thousands):

2003 and 2004..................	$ -
2005...........................	$ 406,704
2006...........................	$ -
2007...........................	$ 161,130
Thereafter.....................	$1,100,702

Line of credit. During May 2000, the Company entered into a $575.0 million corporate credit facility (the "Credit Agreement") with a syndication of banks (the "Banks") that matures on March 1, 2005. Advances under the Credit Agreement bear interest, at the option of the Company, based on (a) a base rate equal to the higher of the Bank of America, N.A. prime rate (4.25 percent at December 31, 2002) or a rate per annum based on the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System (1.16 percent at December 31, 2002), plus 50 basis points; plus a eurodollar margin (the "Eurodollar Margin") less 125 basis points, (b) a Eurodollar rate, substantially equal to the London Interbank Offered Rate ("LIBOR") (1.38 percent at December 31, 2002 for 90 day borrowings), plus a Eurodollar Margin, or (c) a fixed rate (for aggregate advances not exceeding $50 million) as quoted by the Banks pursuant to a request by the Company. The Eurodollar Margin is based on a grid of the Company's debt rating and ratio of total debt to earnings before gain or loss on the disposition of assets; interest expense; income taxes; depreciation, depletion and amortization expense; exploration and abandonment expense and other noncash charges and expenses (the "Total Leverage Ratio"). As of December 31, 2002, the Eurodollar Margin was 137.5 basis points.

The Credit Agreement imposes certain restrictive covenants on the Company, including the maintenance of a Total Leverage Ratio not to exceed 3.75 to 1.00; maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.25 to 1.00; a limitation on the Company's total debt; and, restrictions on certain payments. The Company was in compliance with all of its debt covenants as of December 31, 2002.

As of December 31, 2002 and 2001, the Company had $27.2 million and $27.9 million of undrawn letters of credit issued under the Credit Agreement, respectively, and unused Credit Agreement borrowing capacity of $287.8 million and $253.1 million, respectively.

Senior notes. The Company's senior 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 issuances are structurally subordinated to all obligations of its subsidiaries. Interest on the Company's senior notes is payable semiannually. Pioneer USA has fully and unconditionally guaranteed the senior note issuances. See Note R for a discussion of Pioneer USA debt guarantees and Consolidating Financial Statements.

During April 2002, the Company issued $150.0 million of 7-1/2 percent senior notes due April 15, 2012 (the "7-1/2 percent senior notes"). The 7-1/2 percent senior notes were issued at a price equal to 100 percent of their principal amount and resulted in net proceeds to the Company, after underwriting discounts, commissions and costs of issuance, of $146.7 million. The net proceeds from the issuance of the 7-1/2 percent senior notes were used to reduce outstanding borrowings under the Credit Agreement. The 7-1/2 percent senior notes and 9-5/8 percent senior notes contain various restrictive covenants, including restrictions on the incurrence of additional indebtedness and certain payments defined within the associated indenture. The Company in compliance with all of its senior note covenants as of December 31, 2002.

Early extinguishment of debt and capital cost obligation. During the year ended December 31, 2002, the Company repurchased $47.1 million of its outstanding 9-5/8 percent senior notes, $13.9 million of its outstanding 8-7/8 percent senior notes and repaid a $45.2 million capital cost obligation. The Company recognized extraordinary losses, net of taxes, of $6.7 million and $15.6 million associated with these debt extinguishments, respectively. See Note D for additional information regarding the capital cost obligation that was repaid during the year ended December 31, 2002.

During 2001, the Company redeemed the remaining $22.5 million of outstanding 11-5/8 percent senior subordinated discount notes and $6.8 million of outstanding 10-5/8 percent senior subordinated notes. Additionally, the Company repurchased $38.7 million of its 9-5/8 percent senior notes during 2001. Associated with these debt extinguishments, the Company recognized an extraordinary loss, net of taxes, of $3.8 million during the year ended December 31, 2001.

In May 2000, the Company recognized an extraordinary loss of $12.3 million, net of tax, from the early extinguishment of its prior revolving credit facility.

See Note B for a discussion of the classification of gains and losses on the early extinguishment of debt after the adoption of SFAS 145 on January 1, 2003.

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2002, 2001 and 2000:

	Year ended December 31,		
	2002	2001	2000
	(in thousands)		
Cash payments for interest	$ 113,827	$ 129,992	$ 147,156
Accretion/amortization of discounts or premiums on loans	5,488	7,937	7,995
Amortization of deferred hedge gains (see Note J)	(14,108)	(2,750)	-
Amortization of capitalized loan fees	2,436	2,252	2,769
Kansas ad valorem tax (see Note I)	375	1,250	1,935
Net change in accruals	48	(732)	2,097
Interest incurred	108,066	137,949	161,952
Less interest capitalized	(12,251)	(5,991)	-
Interest expense	$ 95,815	$ 131,958	$ 161,952

NOTE F. Related Party Transactions

Activities with affiliated partnerships. Prior to 1992, the Company, through its wholly-owned subsidiaries, sponsored 44 drilling partnerships, three public income partnerships and 13 affiliated employee partnerships, all of which were formed primarily for the purpose of drilling and completing wells or acquiring producing properties. During 2001, the Company completed the merger of 42 of the limited partnerships into Pioneer USA. During 2000, the Company completed the merger of the 13 employee partnerships into Pioneer USA. See Note D for additional information regarding the mergers.

During 1994, 1993 and 1992, the Company formed a Direct Investment Partnership for the purpose of permitting selected key employees to invest directly, on an unpromoted basis, in wells that the Company drilled in those years. In November 2000, the Company exercised its right under the Direct Investment Partnership agreements to purchase each partner's interest in their respective Direct Investment Partnership. The Company paid $4.3 million to complete the purchase, of which $887 thousand was paid to Company employees.

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.

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2002, 2001 and 2000:

	2002	2001	2000
	(in thousands)		
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$1,495	$9,281	$9,222
Reimbursement of general and administrative expenses	$ 127	$1,265	$1,550

NOTE G. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors 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. The Company will then provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first 10 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 $805 thousand, $652 thousand and $611 thousand for 2002, 2001 and 2000, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. The 401(k) Plan was formed by the merger of the Pioneer Natural Resources USA, Inc. 401(k) Plan and the Pioneer Natural Resources USA, Inc. Matching Plan on January 1, 2002. 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 than 12 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 basic compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, their 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, 2002, 2001 and 2000, the Company recognized compensation expense of $4.1 million, $3.4 million and $3.4 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In August 1997, the Company's stockholders approved the Long-Term Incentive Plan, which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units and restricted stock to directors, officers and employees of the Company. The Long-Term Incentive Plan provides for the issuance of a maximum number of shares of common stock equal to 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company.

The following table calculates the number of shares or options available for grant under the Company's Long-Term Incentive Plan as of December 31, 2002 and 2001:

	December 31, 2002	December 31, 2001
Shares outstanding	117,252,538	103,936,394
Outstanding exercisable options or exercisable within 60 days	5,024,173	4,658,155
	122,276,711	108,594,549
Maximum shares/options allowed under the Long-Term Incentive Plan.	12,227,671	10,859,455
Less: Outstanding awards under Long-Term Incentive Plan	(7,432,414)	(6,377,520)
Outstanding options under predecessor incentive plans	(488,671)	(548,551)
Shares/options available for future grant	4,306,586	3,933,384

Stock option awards. The Company has a program of awarding semi-annual stock options to its officers and employees and gives its non-employee directors a choice to receive (i) 100 percent restricted stock, (ii) 100 percent stock options, (iii) 100 percent cash, or (iv) a combination of 50/50 of any two, as their annual compensation. This program provides for stock option awards at an exercise price based upon the closing sales price of the Company's common stock on the day prior to the date of grant. Employee stock option awards vest over an 18 month or three year schedule and provide a five year exercise period from each vesting date. Non-employee directors' stock options vest quarterly and provide for a five year exercise period from each vesting date. The Company granted 1,643,212; 1,627,071 and 1,439,035 options under the Long-Term Incentive Plan during 2002, 2001 and 2000, respectively.

Restricted stock awards. During the year ended December 31, 2002, the Company issued 654,445 restricted shares of the Company's common stock. The restricted awards were issued as compensation to directors, officers and key employees of the Company. The restricted share awards include 18,545 shares that were granted to directors of the Company on May 13, 2002. Director awards for 3,302 shares vest on a quarterly pro-rata basis during the year ended May 13, 2003 and director awards for 15,243 shares vest on May 13, 2005. The remaining 635,900 restricted shares were awarded to officers and key employees of the Company on August 12, 2002 and vest on August 12, 2005. The Company recorded $16.2 million of deferred compensation in the stockholder's equity section of the accompanying Consolidated Balance Sheet associated with the restricted stock awards, which amount will be amortized to compensation expense over the vesting periods of the awards. During the year ended December 31, 2002, amortization of the restricted stock awards increased the Company's compensation expense by $1.9 million.

The following table reflects the outstanding restricted stock awards and activity related thereto for 2002:

	For the Year Ended December 31, 2002	
	Number of Shares	Weighted Average Price
Restricted Stock Awards:		
Restricted shares outstanding at beginning of year........	-	$ -
Shares granted..	654,445	$ 24.72
Lapse of restrictions...................................	(1,652)	$ 24.60
Restricted shares outstanding at end of year................	652,793	$ 24.72

There were no restricted stock awards to directors or employees during the years ended December 31, 2001 and 2000.

Other stock based plans. Prior to the formation of the Company in 1997, the Company's predecessor companies had long-term incentive plans in place that allowed the predecessor companies to grant incentive awards similar to the provisions of the Long-Term Incentive Plan. Upon formation of the Company, all awards under these plans were assumed by the Company with the provision that no additional awards be granted under the predecessor plans.

SFAS 123 disclosures. The Company applies APB 25 and related interpretations in accounting for its stock option awards. Accordingly, no compensation expense has been recognized for its stock option awards. If compensation expense for the stock option awards had been determined consistent with SFAS 123, the Company's net income and net income per share would have been less than reported amounts. See Note B comparisons of net income and net income per share as reported and as adjusted for the pro forma effects of determining compensation expense in accordance with SFAS 123.

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2002, 2001 and 2000:

	For the Year Ended December 31,		
	2002	2001	2000
Risk-free interest rate............	2.80%	4.13%	5.66%
Expected life......................	5 years	5 years	5 years
Expected volatility................	45%	49%	50%
Expected dividend yield............	-	-	-

A summary of the Company's stock option plans as of December 31, 2002, 2001 and 2000, and changes during the years ended on those dates, are presented below:

	For the Year Ended December 31, 2002		For the Year Ended December 31, 2001		For the Year Ended December 31, 2000	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Non-statutory stock options:						
Outstanding, beginning of year..	6,926,071	$ 18.16	6,510,559	$ 18.10	6,241,889	$ 19.45
Options granted..............	1,643,212	$ 21.14	1,627,071	$ 18.29	1,439,035	$ 10.32
Options forfeited............	(154,717)	$ 26.27	(566,189)	$ 25.83	(798,058)	$ 18.05
Options exercised............	(1,146,274)	$ 12.19	(645,370)	$ 11.14	(372,307)	$ 10.78
Outstanding, end of year........	7,268,292	$ 19.60	6,926,071	$ 18.16	6,510,559	$ 18.10
Exercisable at end of year......	4,269,659	$ 20.15	4,005,762	$ 20.82	3,897,187	$ 23.47
Weighted average fair value of options granted during the year............................	$ 8.87		$ 8.65		$ 4.88	

The following table summarizes information about the Company's stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2002	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2002	Weighted Average Exercise Price
$ 5-11	800,715	3.9 years	$ 8.35	619,504	$ 8.49
$ 12-18	3,805,527	4.9 years	$ 16.69	1,714,584	$ 15.42
$ 19-26	1,288,548	4.9 years	$ 24.13	562,069	$ 23.44
$ 27-30	1,323,242	1.1 years	$ 29.59	1,323,242	$ 29.59
$ 31-52	50,260	2.6 years	$ 39.88	50,260	$ 39.88

7,268,292	4,269,659

Employee Stock Purchase Plan

The Company has an Employee Stock Purchase Plan (the "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 nine month offering period. 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 annual offering period, whichever closing sales price is lower.

NOTE H. Issuance of Common Stock

During April 2002, the Company completed a public offering of 11.5 million shares of its common stock at $21.50 per share. Associated therewith, the Company received $236.0 million of net proceeds after the payment of issuance costs. The Company used the net proceeds from the public offering to fund the acquisition of the Falcon assets and associated acreage in the deepwater Gulf of Mexico and the West Panhandle gas field acquisitions. See Note D for information regarding these acquisitions.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance agreements with its officers, subsidiary company officers and certain key employees. Salaries and bonuses for the Company's officers are set by the Compensation Committee for the parent company officers and by the Management Committee for subsidiary company officers and key employees. These committees can grant increases or reductions to base salary at their discretion. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total approximately $18.2 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 various legal actions incidental to its business, including, but not limited to, the proceedings described below. The majority of these lawsuits primarily involve claims for damages arising from oil and gas leases and ownership interest disputes. The Company believes that the ultimate disposition of these legal actions will not have a material adverse effect on the Company's consolidated financial position, liquidity, capital resources or future results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect the then current status of litigation.

Alford. The Company is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of the Company's gathering systems connected to the Company's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings to add claims regarding the field compression installed by the Company in the 1990's. The lawsuit now has two material claims. First, the plaintiffs assert that the expenses related to the field compression are a "cost of production" for which plaintiffs cannot be charged their proportionate share under the applicable oil and gas leases. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the Company's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the Company's liability could reach $25 million, plus prejudgment interest. However, the Company believes it has valid defenses to plaintiffs' claims, has paid the plaintiffs properly under their respective oil and gas leases, and intends to vigorously defend itself.

The Company believes the cost of the field compression is not a "cost of production", but is rather an expense of transporting the gas to the Company's Satanta gas plant for processing, where valuable hydrocarbon liquids and helium are extracted from the gas. The plaintiffs benefit from such extractions and the Company believes that charging the plaintiffs with their proportionate share of such transportation and processing expenses is consistent with Kansas law. The Company has also vigorously defended against plaintiffs' claims to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases.

The factual evidence in the case was presented to the 26th Judicial District Court without a jury in December 2001. Oral arguments were heard by the court in April 2002, and although the court has not yet entered a judgment or findings, it could do so at any time. The Company strongly denies the existence of any material underpayment to plaintiffs and believes it presented strong evidence at trial to support its positions. The Company has not yet determined the amount of damages, if any, that would be payable if the lawsuit was determined adversely to the Company. Although the amount of any resulting liability could have a material adverse effect on the Company's results of operations for the quarterly reporting period in which such liability is recorded, the Company does not expect that any such liability will have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations.

Kansas ad valorem tax. The Natural Gas Policy Act of 1978 ("NGPA") allows a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price for gas. Based on a Federal Energy Regulatory Commission ("FERC") ruling that Kansas ad valorem tax was such a tax, one of the Company's predecessor entities collected the Kansas ad valorem tax in addition to the otherwise maximum lawful price. The FERC's ruling was appealed to the United States Court of Appeals for the District of Columbia ("D.C. Circuit"), which held in June 1988 that the FERC failed to provide a reasoned basis for its findings and remanded the case to the FERC for further consideration.

On December 1, 1993, the FERC issued an order reversing its prior ruling, but limiting the effect of its decision to Kansas ad valorem taxes for sales made on or after June 28, 1988. The FERC clarified the effective date of its decision by an order dated May 18, 1994. The order clarified that the effective date applies to tax bills rendered after June 28, 1988, not sales made on or after that date. Numerous parties filed appeals on the FERC's action in the D.C. Circuit. Various gas producers challenged the FERC's orders on two grounds: (1) that the Kansas ad valorem tax, properly understood, does qualify for reimbursement under the NGPA; and (2) the FERC's ruling should, in any event, have been applied prospectively. Other parties challenged the FERC's orders on the grounds that the FERC's ruling should have been applied retroactively to December 1, 1978, the date of the enactment of the NGPA and producers should have been required to pay refunds accordingly.

The D.C. Circuit issued its decision on August 2, 1996, which holds that producers must make refunds of all Kansas ad valorem tax collected with respect to production since October 4, 1983, as opposed to June 28, 1988. Petitions for rehearing were denied on November 6, 1996. Various gas producers subsequently filed a petition for writ of certiori with the United States Supreme Court seeking to limit the scope of the potential refunds to tax bills rendered on or after June 28, 1988 (the effective date originally selected by the FERC). Williams Natural Gas Company filed a cross-petition for certiori seeking to impose refund liability back to December 1, 1978. Both petitions were denied on May 12, 1997.

The Company and other producers filed petitions for adjustment with the FERC on June 24, 1997. The Company was seeking waiver or set-off from FERC with respect to that portion of the refund associated with (i) non-recoupable royalties, (ii) non-recoupable Kansas property taxes based, in part, upon the higher prices collected, and (iii) interest for all periods. On September 10, 1997, FERC denied this request, and on October 10, 1997, the Company and other producers filed a request for rehearing. Pipelines were given until November 10, 1997 to file claims on refunds sought from producers and refunds totaling approximately $30.2 million were made against the Company. Through December 31, 2002, the Company has settled $21.7 million of the original claim amounts, of which $11.8 million was settled during 2002. The carrying value of the obligation settled during 2002 exceeded the settlement paid by the Company by $3.5 million. Accordingly, the Company recognized other income of $3.5 million during 2002. As of December 31, 2002 and December 31, 2001, the Company had on deposit $10.6 million and $24.5 million, respectively, including accrued interest, in an escrow account and had corresponding obligations for the remaining claims recorded in other current liabilities in the accompanying Consolidated Balance Sheets. The Company believes that the escrowed amounts, plus accrued interest, will be sufficient to settle the remaining claims.

Lease agreements. The Company leases offshore production facilities, equipment and office facilities under noncancellable operating leases on which rental expense for the years ended December 31, 2002, 2001 and 2000 was approximately $6.7 million, $6.6 million and $7.0 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2002 are as follows (in thousands):

2003.......................................	$ 19,364
2004.......................................	$ 41,553
2005.......................................	$ 39,375
2006.......................................	$ 32,266
2007.......................................	$ 26,258
Thereafter.................................	$ 36,338

Transportation agreements. The Company's wholly-owned Canadian subsidiary is a party to pipeline transportation service agreements, with remaining terms of approximately 13 years, whereby it has committed to transport a specified volume of gas each year from Canada to a point in Chicago, Illinois. Such gas volumes are comprised of a significant portion of the Company's Canadian net production, augmented with certain volumes purchased at market prices in Canada. The committed volumes to be transported under the pipeline transportation service agreements are approximately 84 MMcf of gas per day during 2003 and decline to approximately 80 MMcf of gas per day by the end of the commitment term. The net gas marketing gains or losses resulting from purchasing third party gas in Canada and selling it in Chicago are recorded as other income or other expense in the accompanying Consolidated Statements of Operations. Associated with these agreements, the Company recognized $2.6 million and $9.9 million of gas marketing losses in other expenses during 2002 and 2001, respectively.

NOTE J. Derivative Financial Instruments

Hedge Derivatives

The Company, from time to time, uses derivative instruments to manage interest rate, commodity price and currency exchange rate risks.

Fair value hedges. The Company monitors capital markets and trends to identify opportunities to enter into interest rate swaps to minimize its costs of capital. As of December 31, 2002, the Company was not a party to any fair value hedges. As of December 31, 2001, the carrying value of the Company's fair value hedges was a liability of $19.6 million.

During April 2000 and May 2001, the Company entered into interest rate swap agreements to hedge the fair value of the Company's 8-7/8 percent senior notes and 8-1/4 percent senior notes, respectively. The terms of the interest rate swap agreements matched the notional amounts and scheduled maturities of the bonds; required the counterparties to pay the Company a fixed annual interest rate equal to the stated bond coupon rates on the notional amounts; and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus weighted average margin rates of 178.2 basis points and 238.1 basis points on the 8-7/8 percent senior notes and 8-1/4 percent senior notes; respectively. During September 2001, the Company terminated its 8-7/8 percent and 8-1/4 percent interest rate swaps for $23.3 million of cash proceeds, including accrued interest.

During April 2002 the Company entered into interest rate swap agreements to hedge the fair value of the Company's 8-7/8 percent senior notes and, during November 2001, the Company entered into interest rate swap agreements to hedge the fair value of its 6-1/2 percent senior notes and 8-1/4 percent senior notes. The terms of the interest rate swap agreements matched the notional amounts and scheduled maturities of the bonds; required the counterparties to pay the Company fixed annual interest rates equal to the stated bond coupon rates on the notional amounts; and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus weighted average margin rates of 397 basis points, 202.2 basis points, and 337 basis points on the 8-7/8 percent senior notes, 6-1/2 percent senior notes and 8-1/4 percent senior notes; respectively. During September 2002, the Company terminated these interest rate swaps for $36.3 million of cash proceeds, including accrued interest.

As of December 31, 2002, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included $35.7 million of incremental liability attributable to the unamortized deferred hedge gains realized from the terminations of the Company's fair value hedge agreements during 2002 and 2001. The amortization of these deferred hedge gains reduced the Company's reported interest expense by $14.1 million and $2.8 million during the years ended December 31, 2002 and 2001, respectively.

The following table sets forth the scheduled amortization of deferred hedge gains on terminated fair value hedges that will be recognized as reductions in the Company's future interest expense:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Total
			(in thousands)		
2003 hedge gain amortization..........	$ 5,937	$ 5,564	$ 4,735	$ 4,161	$ 20,397
2004 hedge gain amortization..........	$ 3,518	$ 3,122	$ 2,458	$ 2,105	11,203
Remaining net gains to be amortized through 2008........................					4,072
					$ 35,672

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The terms of the fair value hedges described above perfectly matched the terms of the underlying senior notes. Thus, the Company did not exclude any component of the derivatives' gains or losses from the measurement of hedge effectiveness.

Cash flow hedges. The Company utilizes, from time to time, 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. The Company has also utilized interest rate swap agreements to reduce the effect of interest rate volatility on the Company's variable rate line of credit indebtedness and forward currency exchange agreements to reduce the effect of U.S. dollar to Canadian dollar exchange rate volatility.

Oil. All material sales contracts governing the Company's oil production have been tied directly or indirectly to the New York Mercantile Exchange prices. The following table sets forth the Company's outstanding oil hedge contracts and the weighted average NYMEX prices for those contracts as of December 31, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Total
Daily oil production:					
2003 - Swap Contracts					
Volume (Bbl)....................	19,900	23,000	23,000	23,000	22,236
Price per Bbl...................	$ 24.59	$ 24.44	$ 24.40	$ 24.40	$ 24.45
2004 - Swap Contracts					
Volume (Bbl)....................	14,000	14,000	14,000	14,000	14,000
Price per Bbl...................	$ 23.11	$ 23.11	$ 23.11	$ 23.11	$ 23.11

The Company reports average oil prices per Bbl including the effects of oil quality adjustments and the net effect of oil hedges. The following table sets forth the Company's oil prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of oil price hedges to revenue:

	Year Ended December 31, 2002	2001	2000
Average price reported per Bbl......................	$ 22.89	$ 24.12	$ 24.01
Average price realized per Bbl......................	$ 22.95	$ 23.88	$ 28.81
Addition (reduction) to revenue (in millions).......	$ (.8)	$ 3.0	$ (60.1)

Natural gas liquids prices. During the years ended December 31, 2002, 2001 and 2000, the Company did not enter into any NGL hedge contracts.

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. The following table sets forth the Company's outstanding gas hedge contracts and the weighted average index prices for those contracts as of December 31, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily gas production:					
2003 - Swap Contracts					
Volume (Mcf)..............	230,000	230,000	230,000	230,000	230,000
Index price per MMBtu......	$ 3.76	$ 3.76	$ 3.76	$ 3.76	$ 3.76
2004 - Swap Contracts					
Volume (Mcf)..............	180,000	180,000	180,000	180,000	180,000
Index price per MMBtu......	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81
2005 - Swap Contracts					
Volume (Mcf)..............	10,000	10,000	10,000	10,000	10,000
Index price per MMBtu......	$ 3.70	$ 3.70	$ 3.70	$ 3.70	$ 3.70
2006 - Swap Contracts					
Volume (Mcf)..............	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu......	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75
2007 - Swap Contracts					
Volume (Mcf)..............	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu......	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75

The Company reports average gas prices per Mcf including the effects of Btu content, gas processing and shrinkage adjustments and the net effect of gas hedges. The following table sets forth the Company's gas prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of gas price hedges to revenue:

	Year Ended December 31,		
	2002	2001	2000
Average price reported per Mcf.....................	$ 2.49	$ 3.23	$ 2.81
Average price realized per Mcf.....................	$ 2.38	$ 3.20	$ 3.03
Addition/(reduction) to revenue (in millions).......	$ 13.6	$ 3.0	$(29.0)

Interest rates. During the year ended December 31, 2001, the Company entered into interest rate swap agreements and designated the swap agreements as being cash flow hedges of the interest rate volatility associated with a portion of the Company's variable rate line of credit indebtedness. The terms of the interest rate swap agreements provided for an aggregate notional amount of $55 million of debt; commenced on May 21, 2001 and matured on May 20, 2002; required the counterparties to pay the Company a variable rate equal to the periodic six-month LIBOR plus 125 basis points; and, required the Company to pay the counterparties a weighted average annual rate of 5.43 percent on the notional amount. The Company recognized interest expense of $447 thousand and $185 thousand associated with these interest rate swap agreements during the years ended December 31, 2002 and 2001, respectively. The Company recognized no ineffectiveness associated with changes in the fair values of these derivative instruments.

Foreign currency rates. During 2001, the Company entered into forward agreements to exchange an aggregate $24.8 million U.S. dollars for Canadian dollars at a weighted average exchange rate of .6266 U.S. dollars for 1.0 Canadian dollar. These agreements were designated as hedges of the Company's exchange rate risk associated with Canadian sales of gas under U.S. dollar denominated sales agreements. The Company recognized settlement gains of $249 thousand associated with these forward agreements during the year ended December 31, 2002, which increased the Company's reported gas price. The Company did not recognize any ineffectiveness associated with changes in the fair values of these derivative instruments. Except for one forward agreement that represented an asset of $15 thousand to the Company on December 31, 2002, these agreements matured during the year ended December 31, 2002.

Hedge ineffectiveness and excluded items. During the years ended December 31, 2002 and 2001, the Company recognized other expense of $1.7 million and $9.1 million, respectively, related to the ineffective portions of its cash flow hedging instruments. Additionally, based on SFAS 133 interpretive guidance that was in effect prior to April 2001, the Company excluded from the measurement of hedge effectiveness changes in the time and volatility value components of collar contracts designated as cash flow hedges. Associated therewith, the Company recorded other expense of $2.4 million during the three month period ended March 31, 2001. In April 2001, the Company discontinued the exclusion of time value and volatility from the measurement of hedge effectiveness.

Accumulated other comprehensive income - deferred hedge gains and losses, net. As described in Note B, the Company records the effective portions of deferred cash flow hedge gains and losses in AOCI - deferred hedge gains, net. Once the underlying hedged transaction occurs the deferred hedge gain or loss is reclassified from AOCI - deferred hedge gains, net to earnings. If it is determined that the underlying hedged transaction is not likely to occur, the deferred hedge gain or loss is reclassified from AOCI - deferred hedge gains, net to other income or other expense during the period in which it is determined that the underlying hedged transaction is not likely to occur. As of December 31, 2002 and 2001, AOCI - deferred hedge gains, net represented net deferred gains of $9.6 million and $201.0 million, respectively. The AOCI - deferred hedge gains, net balance as of December 31, 2002 was comprised of $107.8 million of unrealized deferred hedge losses on the effective portions of open commodity cash flow hedges and $117.4 million of net deferred gains on terminated cash flow hedges. The AOCI - deferred hedge gains, net balance as of December 31, 2001 was comprised of $177.7 million of unrealized deferred gains on the effective portions of open commodity, interest rate and forward currency rate cash flow hedges and $23.3 million of net deferred gains on terminated cash flow hedges. The decrease in AOCI - deferred hedge gains, net during the year ended December 31, 2002 was primarily attributable to increases in future commodity prices relative to the commodity prices stipulated in the hedge agreements and the reclassification of deferred hedge gains to net income as derivatives matured by their terms. The unrealized deferred hedge gains and 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 agreements or terminated prior to settlement. The net deferred gains and losses on terminated cash flow hedges are fixed.

During the twelve month period ending December 31, 2003, the Company expects to reclassify $73.6 million of net deferred losses associated with open cash flow hedges and $72.1 million of net deferred gains on terminated cash flow hedges from AOCI - deferred hedge gains, net to oil and gas revenue.

The following table sets forth the scheduled reclassifications of deferred hedge gains on terminated cash flow hedges that will be recognized in the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total Year
			(in thousands)		
2003 deferred hedge gains.........	$ 18,123	$ 18,043	$ 18,021	$ 17,864	$ 72,051
2004 deferred hedge gains.........	$ 11,206	$ 11,156	$ 11,226	$ 11,175	44,763
2005 deferred hedge gains.........	$ 149	$ 153	$ 156	$ 158	616
					$ 117,430

Non-hedge Derivatives

Btu swap agreements. The Company is a party to Btu swap agreements that mature at the end of 2004. The Btu swap agreements do not qualify for hedge accounting treatment. The Company recorded mark-to-market adjustments to decrease the carrying value of the Btu swap liability by $.7 million during the year ended December 31, 2001 and to increase the carrying value of the Btu swap liability by $14.6 million during the year ended December 31, 2000.

During the year ended December 31, 2001, the Company entered into offsetting Btu swap agreements that fixed the Company's remaining obligations associated with the Btu swap agreements. The undiscounted future settlement obligations of the Company under the Btu swap agreements are $7.2 million per year for each of 2003 and 2004.

Foreign currency agreements. Prior to their maturity in 2000, the Company was a party to a series of forward foreign exchange rate swap agreements that exchanged Canadian dollars for U.S. dollars. These contracts did not qualify as hedges. The Company recorded a mark-to-market adjustment to increase the carrying value of the foreign exchange swap liabilities by $1.9 million during the year ended December 31, 2000.

Other non-hedge commodity derivatives. During the year ended December 31, 1999, the Company sold call options that provided the counterparties an option to exercise calls either on 10,000 Bbls per day of oil, at a strike price of $20.00 per Bbl, or on 100,000 MMBtu per day of gas, at a weighted average strike price of $2.75 per MMBtu. These contracts, which matured during the year ended December 31, 2000, did not qualify for hedge accounting treatment. The Company recorded mark-to-market adjustments to increase the carrying value of the associated contract liability by $42.0 million during the year ended December 31, 2000.

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. 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 customers individually accounted for 10 percent or more of the consolidated oil, NGL and gas revenues of the Company during one or more of the years ended December 31, 2002, 2001 and 2000:

	Percentage of Consolidated Oil, NGL and Gas Revenues		
	2002	2001	2000
Williams Energy Services............	7	11	13
Anadarko Petroleum Corporation.......	7	10	6

At December 31, 2002, the amounts receivable from Williams Energy Services and Anadarko Petroleum Corporation were $13.4 million and $11.7 million, respectively, which are included in the caption "Accounts receivable - trade" in the accompanying Consolidated Balance Sheet.

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, 2002 and 2001, the Company has $7.6 million of derivative assets for which Enron North America Corp was the Company's counterparty. Associated therewith, the Company recognized bad debt expense of $.4 million and $6.0 million during the years ended December 31, 2002 and 2001, respectively, which amounts are included in other expense in the accompanying Consolidated Statements of Operations.

NOTE L. Interest and Other Income

The Company recorded interest and other income of $11.2 million, $21.8 million and $25.8 million during the years ended December 31, 2002, 2001 and 2000. The major categories of the Company's interest and other income are summarized in the following table:

	Year Ended December 31,		
	2002	2001	2000
	(in thousands)		
Kansas ad valorem escrow adjustments (see Note I)	$ 3,500	$ 1,100	$ 1,000
Excise tax income	2,398	4,126	6,915
Production payment income	-	5,552	1,262
Interest income	642	2,128	3,906
Seismic data sales	87	1,841	1,148
Foreign exchange gains	142	223	220
Other income	4,453	6,808	11,324
	$ 11,222	$ 21,778	$ 25,775

NOTE M. Asset Divestitures

During the years ended December 31, 2002, 2001 and 2000, the Company completed asset divestitures for net proceeds of $118.9 million, $113.5 million and $102.7 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $4.4 million, $7.7 million and $34.2 million during the years ended December 31, 2002, 2001 and 2000, respectively.

Hedge derivative divestitures. During the years ended December 31, 2002 and 2001, the Company terminated, prior to their scheduled maturity, hedge derivatives for cash sales proceeds of $91.3 million and $85.4 million, respectively. Net gains from these divestitures were deferred and are being amortized over the original contract lives of the terminated derivatives as reductions to interest expense or increases to oil and gas revenues. See Note J for more information regarding deferred gains on terminated hedge derivatives.

Available for sale securities divestitures. During the year ended December 31, 2000, the Company sold 3,370,982 shares of common stock of a non-affiliated entity for $59.7 million, recording an associated gain on disposition of assets of $34.3 million. During 2001, the Company sold its remaining 613,250 shares of the non-affiliated entity for $12.7 million of cash proceeds and recognized an associated gain on disposition of assets of $8.1 million.

Other United States divestitures. During the year ended December 31, 2002, the Company received $20.9 million of proceeds from the cash settlement of a gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $1.8 million from the sale of other corporate assets. Associated with these divestitures, the Company recorded net gains of $4.2 million.

During the year ended December 31, 2001, the Company sold other corporate assets for $3.0 million of proceeds. Associated with the sale of these assets, the Company recorded a net gain of $.4 million.

During the year ended December 31, 2000, the Company sold an office building in Midland, Texas, certain other assets and non-strategic oil and gas properties primarily located in the United States Gulf Coast and Mid Continent areas. Associated with these divestitures, the Company realized net divestment proceeds of $43.0 million and recorded a net loss on disposition of assets of $.4 million.

Other international divestitures. During the year ended December 31, 2002, other Canadian and Argentine corporate assets were sold for $.2 million. The Company recorded $.2 million of net gains associated with those

divestitures. During the year ended December 31, 2001, the Company received $12.0 million of proceeds from the sale of certain oil properties in Canada and $.4 million of proceeds from the sale of other international assets. Associated with these transactions, the Company recognized a net loss of $.8 million.

NOTE N. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2002, 2001 and 2000:

	Years Ended December 31,		
	2002	2001	2000
	(in thousands)		
Derivative ineffectiveness and mark-to-market provisions (see Note J)	$ 1,664	$ 11,458	$ 58,518
Gas marketing losses (see Note I)	2,556	9,850	-
Foreign currency remeasurement and exchange losses (a)	7,623	8,474	80
Bad debt expense (see Note K)	129	6,152	65
Other charges	5,284	3,654	8,568
	$ 17,256	$ 39,588	$ 67,231

<FN>

(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. In early January 2002, the Argentine government severed the one-to-one relationship between the value of the Argentine peso and the U.S. dollar, which is the functional currency of the Company's Argentine operations. Consequently, the Company has remeasured its Argentine peso-denominated monetary net assets as of December 31, 2002 and 2001 and adjusted its lease and well equipment inventory balances to market values as of December 31, 2001. Associated therewith, the Company recognized charges of $6.9 million and $7.7 million during 2002 and 2001, respectively.

</FN>

NOTE O. Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes". 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 and foreign taxing authorities. Current and estimated tax payments of $2.3 million, $11.7 million and $4.6 million were made during the years ended December 31, 2002, 2001 and 2000, respectively. During the years ended December 31, 2002, 2001 and 2000, the Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items:

	Year Ended December 31,		
	2002	2001	2000
	(in thousands)		
Income (loss) before extraordinary items.......	$ 5,063	$ 4,016	$ (6,000)
Changes in other comprehensive income:			
Deferred hedge gains and losses..............	(2,561)	2,293	-
Cumulative translation adjustment............	(20)	(121)	(200)
	$ 2,482	$ 6,188	$ (6,200)

Income tax provision (benefit) attributable to income (loss) before extraordinary items consists of the following:

	Year Ended December 31,		
	2002	2001	2000
	(in thousands)		
Current:			
U.S. state and local................	$ 209	$ 1,080	$ -
Foreign............................	2,066	10,585	4,600
	2,275	11,665	4,600
Deferred:			
Foreign............................	2,788	(7,649)	(10,600)
Total................................	$ 5,063	$ 4,016	$ (6,000)

Income (loss) before income taxes and extraordinary items consists of the following:

	Year Ended December 31,		
	2002	2001	2000
	(in thousands)		
Income (loss) before income taxes and extraordinary items:			
U.S. federal.......................	$ 58,821	$ 140,045	$ 138,941
Foreign............................	(4,699)	(32,280)	19,558
	$ 54,122	$ 107,765	$ 158,499

Reconciliations of the United States federal statutory rate to the

Company's effective rate for income (loss) before extraordinary items are as follows:

	2002	2001	2000
U.S. federal statutory tax rate.......	35.0	35.0	35.0
Valuation allowance..................	(23.7)	(27.5)	(30.9)
Rate differential on foreign operations..........................	(.1)	(3.2)	(2.9)
Other...............................	(1.8)	(.6)	(5.0)
Consolidated effective tax rate.......	9.4	3.7	(3.8)

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

	December 31,	
	2002	2001
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards....................	$ 299,495	$ 341,206
Alternative minimum tax credit carryforwards.........	1,565	1,565
Other..	143,894	44,745
Total deferred tax assets.........................	444,954	387,516
Valuation allowance................................	(277,217)	(183,122)
Net deferred tax assets...........................	167,737	204,394
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes.................................	80,364	115,524
Other..	5,393	11,919
Total deferred tax liabilities....................	85,757	127,443
Net deferred tax asset...........................	$ 81,980	$ 76,951

Realization of deferred tax assets associated with net operating loss carryforwards ("NOLs") and other credit carryforwards is dependent upon generating sufficient taxable income prior to their expiration. The Company believes that there is a risk that certain of these NOLs and other credit carryforwards may expire unused and, accordingly, has a valuation allowance of $277.2 million against the carryforwards at December 31, 2002. Although realization is not assured for the remaining deferred tax asset, the Company believes it is more likely than not that they will be realized through future taxable earnings or alternative tax planning strategies. However, the net deferred tax assets could be reduced further if the Company's estimate of taxable income in future periods is significantly reduced or alternative tax planning strategies are no longer viable.

At December 31, 2002, the Company had NOLs for United States, Canadian, South African, Gabonese and Tunisian income tax purposes of $742.7 million, $37.4 million, $40.3 million, $13.4 million and $8.7 million, respectively, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, at December 31, 2002, the Company has alternative minimum tax net operating loss carryforwards ("AMT NOLs") in the United States of $637.5 million, which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

Expiration Date	U.S. NOL	U.S. AMT NOL	Canada NOL	South Africa NOL	Gabon NOL	Tunisia NOL
	(in thousands)					
December 31, 2005......	$ -	$ -	$ 31,637	$ -	$ -	$ -
December 31, 2006......	-	-	5,738	-	-	-
December 31, 2007......	13,320	-	-	-	-	-
December 31, 2008......	112,508	104,574	-	-	-	-
December 31, 2009......	129,226	102,727	-	-	-	-
December 31, 2010......	124,859	110,961	-	-	-	-
December 31, 2011......	6,521	4,045	-	-	-	-
December 31, 2012......	68,334	58,723	-	-	-	-
December 31, 2018......	127,656	98,290	-	-	-	-
December 31, 2019......	145,999	144,837	-	-	-	-
December 31, 2020......	14,235	13,297	-	-	-	-
Indefinite............	-	-	-	40,304	13,397	8,712
Total...............	$ 742,658	$ 637,454	$ 37,375	$ 40,304	$ 13,397	$ 8,712

The Company believes $160.0 million of the U.S. NOLs and AMT NOLs are subject to Section 382 of the Internal Revenue Code and are limited in each taxable year to approximately $20.0 million.

NOTE P. 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 operations in the United States, Argentina and Canada. Other foreign is primarily comprised of operations in South Africa, Gabon and Tunisia.

The following table provides the geographic operating segment data required by Statement of Financial Accounting Standards 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 Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities". 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 and Other" table column includes revenues, expenses, additions to properties, plants and equipment and assets that are not routinely included in the earnings measures or attributes internally reported to management on a geographic operating segment basis.

	United States	Argentina	Canada	Other Foreign	Headquarters and Other	Consolidated Total
	(in thousands)					
Year Ended December 31, 2002:						

Oil and gas revenues....................	$ 573,289	$ 77,615	$ 50,876	$ -	$ -	$ 701,780
Interest and other......................	-	-	-	-	11,222	11,222
Gain (loss) on disposition of assets.....	3,248	(3)	995	-	192	4,432
	576,537	77,612	51,871	-	11,414	717,434
Production costs........................	174,929	13,870	10,771	-	-	199,570
Depletion, depreciation and amortization.	140,107	39,659	27,857	-	8,752	216,375
Exploration and abandonments............	62,955	10,306	5,841	6,792	-	85,894
General and administrative..............	-	-	-	-	48,402	48,402
Interest................................	-	-	-	-	95,815	95,815
Other...................................	-	-	-	-	17,256	17,256
	377,991	63,835	44,469	6,792	170,225	663,312
Income (loss) before income taxes and extraordinary items....................	198,546	13,777	7,402	(6,792)	(158,811)	54,122
Income tax benefit (provision)...........	(69,491)	(4,822)	(3,118)	2,377	69,991	(5,063)
Income (loss) before extraordinary items.	$ 129,055	$ 8,955	$ 4,284	$ (4,415)	$ (88,820)	$ 49,059
Cost incurred for long-lived assets......	$ 533,560	$ 35,121	$ 33,506	$ 70,268	$ -	$ 672,455
Segment assets (as of December 31).......	$2,375,505	$ 680,063	$ 176,110	$ 118,070	$ 105,368	$3,455,116
Year Ended December 31, 2001:						
Oil and gas revenues....................	$ 649,635	$ 130,241	$ 67,146	$ -	$ -	$ 847,022
Interest and other......................	-	-	-	-	21,778	21,778
Gain (loss) on disposition of assets.....	224	-	(1,339)	-	8,796	7,681
	649,859	130,241	65,807	-	30,574	876,481
Production costs........................	170,578	26,614	12,472	-	-	209,664
Depletion, depreciation and amortization.	128,477	51,391	28,868	-	13,896	222,632
Exploration and abandonments............	70,049	23,857	9,882	24,118	-	127,906
General and administrative..............	-	-	-	-	36,968	36,968
Interest................................	-	-	-	-	131,958	131,958
Other...................................	-	-	-	-	39,588	39,588
	369,104	101,862	51,222	24,118	222,410	768,716
Income (loss) before income taxes and extraordinary items....................	280,755	28,379	14,585	(24,118)	(191,836)	107,765
Income tax benefit (provision)...........	(98,264)	(9,933)	(6,216)	8,441	101,956	(4,016)
Income (loss) before extraordinary items.	$ 182,491	$ 18,446	$ 8,369	$ (15,677)	$ (89,880)	$ 103,749
Cost incurred for long-lived assets......	$ 454,229	$ 98,311	$ 36,048	$ 57,972	$ -	$ 646,560
Segment assets (as of December 31).......	$2,212,540	$ 710,702	$ 187,841	$ 53,314	$ 106,656	$3,271,053
Year Ended December 31, 2000:						
Oil and gas revenues....................	$ 649,273	$ 140,990	$ 62,475	$ -	$ -	$ 852,738
Interest and other......................	-	-	-	-	25,775	25,775
Gain on disposition of assets...........	4,690	-	335	-	29,159	34,184
	653,963	140,990	62,810	-	54,934	912,697
Production costs........................	155,075	24,417	9,773	-	-	189,265
Depletion, depreciation and amortization.	121,932	52,141	25,132	-	15,733	214,938
Exploration and abandonments............	40,867	25,388	5,131	16,164	-	87,550
General and administrative..............	-	-	-	-	33,262	33,262
Interest................................	-	-	-	-	161,952	161,952
Other...................................	-	-	-	-	67,231	67,231
	317,874	101,946	40,036	16,164	278,178	754,198
Income (loss) before income taxes and extraordinary item....................	336,089	39,044	22,774	(16,164)	(223,244)	158,499
Income tax benefit (provision)...........	(117,631)	(13,665)	(10,162)	5,657	141,801	6,000
Income (loss) before extraordinary item..	$ 218,458	$ 25,379	$ 12,612	$ (10,507)	$ (81,443)	$ 164,499
Cost incurred for long-lived assets......	$ 204,122	$ 68,430	$ 43,591	$ 23,597	$ -	$ 339,740
Segment assets (as of December 31).......	$1,899,633	$ 702,868	$ 227,250	$ 16,552	$ 108,132	$2,954,435

NOTE Q. Income Per Share Before Extraordinary Items

Basic income per share before extraordinary items is computed by dividing income before extraordinary items by the weighted average number of common shares outstanding for the period. The computation of diluted income per share before extraordinary items reflects the potential dilution that could occur if securities or other contracts to issue common stock 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.

The following table is a reconciliation of the basic and diluted weighted average common shares outstanding for the years ended December 31, 2002, 2001 and 2000:

	Year Ended December 31,		
	2002	2001	2000
	(in thousands)		
Weighted average common shares outstanding:			
Basic	112,542	98,529	99,378
Dilutive common stock options (a)	1,725	1,185	385
Restricted stock awards (b)	21	-	-
Diluted	114,288	99,714	99,763

<FN>

(a) Common stock options to purchase 1,925,743 shares, 3,595,880 shares and 4,911,749 shares of common stock were outstanding but not included in the computations of diluted net income per share for 2002, 2001 and 2000, respectively, because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(b) During the year ended December 31, 2002, the Company issued 654,445 restricted shares of the Company's common stock. The restricted shares were issued as compensation to directors, officers and key employees of the Company. The restricted shares include 18,545 shares that were granted to directors of the Company on May 13, 2002. Director awards for 3,302 shares vest on a quarterly pro-rata basis during the year ended May 13, 2003, and director awards for 15,243 shares vest on May 13, 2005. The remaining 635,900 restricted shares were awarded to officers and key employees of the Company on August 12, 2002 and vest on August 12, 2005.

</FN>

NOTE R. Pioneer USA

Pioneer USA is a wholly-owned subsidiary of the Company that has fully and unconditionally guaranteed certain debt securities of the Company (see Note E above). The Company has not prepared financial statements and related disclosures for Pioneer USA under separate cover because management of the Company has determined that such information is not material to investors. In accordance with practices accepted by the United States Securities and Exchange Commission, the Company has prepared Consolidating Condensed Financial Statements in order to quantify the assets of Pioneer USA as a subsidiary guarantor. The following Consolidating Condensed Balance Sheets as of December 31, 2002 and 2001, and Consolidating Statements of Operations and Comprehensive Income (Loss) and Consolidating Condensed Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000 present financial information for Pioneer Natural Resources Company as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Pioneer USA on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the non-guarantor subsidiaries of the Company on a consolidated basis, the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis, and the financial information for the Company on a consolidated basis. Pioneer USA is not restricted from making distributions to the Company.

CONSOLIDATING CONDENSED BALANCE SHEET

As of December 31, 2002

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	The Company
			(in thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 6	$ 1,783	$ 6,701	$	$ 8,490
Other current assets	1,727,828	(1,480,657)	(108,568)		138,603
Total current assets	1,727,834	(1,478,874)	(101,867)		147,093
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	3,024,845	1,228,052		4,252,897
Unproved properties	-	43,969	175,104		219,073
Accumulated depletion, depreciation and amortization	-	(947,091)	(356,450)		(1,303,541)
	-	2,121,723	1,046,706		3,168,429
Deferred income taxes	75,311	-	1,529		76,840
Other property and equipment, net	-	19,000	3,784		22,784
Other assets, net	16,067	14,231	9,672		39,970
Investment in subsidiaries	1,247,042	136,159	-	(1,383,201)	-
	$ 3,066,254	$ 812,239	$ 959,824		$ 3,455,116
LIABILITIES AND STOCKHOLDERS' EQUITY					
Total current liabilities	$ 30,785	$ 216,065	$ 27,742	$	$ 274,592
Long-term debt, less current maturities	1,668,536	-	-		1,668,536
Other noncurrent liabilities	-	147,970	(19,639)		128,331
Deferred income taxes	-	-	8,760		8,760
Stockholders' equity	1,366,933	448,204	942,961	(1,383,201)	1,374,897
Commitments and contingencies	-	-	-		-
	$ 3,066,254	$ 812,239	$ 959,824		$ 3,455,116

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2001

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	The Company
			(in thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 79	$ 10,900	$ 3,355	$	$ 14,334
Other current assets	1,540,985	(1,125,968)	(173,708)		241,309
Total current assets	1,541,064	(1,115,068)	(170,353)		255,643
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	2,688,962	1,002,821		3,691,783
Unproved properties	-	25,222	162,563		187,785
Accumulated depletion, depreciation and amortization	-	(815,323)	(279,987)		(1,095,310)
	-	1,898,861	885,397		2,784,258
Deferred income taxes	82,811	-	1,508		84,319
Other property and equipment, net	-	17,881	3,679		21,560
Other assets, net	15,911	81,356	28,006		125,273
Investment in subsidiaries	1,060,457	87,636	-	(1,148,093)	-
	$ 2,700,243	$ 970,666	$ 748,237		$ 3,271,053
LIABILITIES AND STOCKHOLDERS' EQUITY					
Total current liabilities	$ 30,745	$ 176,442	$ 21,022	$	$ 228,209
Long-term debt, less current maturities	1,577,304	-	-		1,577,304
Other noncurrent liabilities	19,582	124,552	22,249		166,383
Deferred income taxes	-	-	13,768		13,768
Stockholders' equity	1,072,612	669,672	691,198	(1,148,093)	1,285,389
Commitments and contingencies	-	-	-		-
	$ 2,700,243	$ 970,666	$ 748,237		$ 3,271,053

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
AND COMPREHENSIVE LOSS
For the Year Ended December 31, 2002
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues and other income:						
Oil and gas	$ -	$ 527,189	$ 174,591	$ -	$	$ 701,780
Interest and other	-	8,214	3,008	-		11,222
Gain on disposition of assets, net	-	3,230	1,202	-		4,432
	-	538,633	178,801	-		717,434
Costs and expenses:						
Oil and gas production	-	165,669	33,901	-		199,570
Depletion, depreciation and amortization	-	139,822	76,553	-		216,375
Exploration and abandonments	-	62,982	22,912	-		85,894
General and administrative	1,323	37,723	9,356	-		48,402
Interest	17,451	76,820	1,544	-		95,815
Equity (income) loss from subsidiary	(52,580)	8,374	-	-	44,206	-
Other	405	4,879	11,972	-		17,256
	(33,401)	496,269	156,238	-		663,312
Income before income taxes	33,401	42,364	22,563	-		54,122
Income tax provision	-	-	(5,063)	-		(5,063)
Income before extraordinary items	33,401	42,364	17,500	-		49,059
Extraordinary items - loss on early extinguishment of debt	(6,688)	-	(15,658)	-		(22,346)
Net income	26,713	42,364	1,842	-		26,713
Other comprehensive income (loss):						
Deferred hedge gains, net:						
Deferred hedge losses	(4)	(156,396)	(22,667)	-		(179,067)
Net (gains) losses included in net income	447	(10,352)	(2,519)	-		(12,424)
Translation adjustment	-	-	2,188	-		2,188
Comprehensive income (loss)	$ 27,156	$(124,384)	$ (21,156)	$ -		$(162,590)

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
AND COMPREHENSIVE INCOME
For the Year Ended December 31, 2001
(in thousands)

Pioneer
Natural

	Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues and other income:						
Oil and gas	$ -	$ 626,964	$ 220,058	$ -	$	$ 847,022
Interest and other	368	14,415	6,995	-		21,778
Gain (loss) on disposition of assets, net	-	8,524	(843)	-		7,681
	368	649,903	226,210	-		876,481
Costs and expenses:						
Oil and gas production	-	168,287	41,377	-		209,664
Depletion, depreciation and amortization	-	135,838	86,794	-		222,632
Exploration and abandonments	-	73,649	54,257	-		127,906
General and administrative	804	25,476	10,688	-		36,968
Interest	31,261	83,473	17,224	-		131,958
Equity (income) loss from subsidiary	(135,459)	5,588	-	-	129,871	-
Other	-	9,247	30,341	-		39,588
	(103,394)	501,558	240,681	-		768,716
Income (loss) before income taxes	103,762	148,345	(14,471)	-		107,765
Income tax provision	-	(783)	(3,220)	(13)		(4,016)
Income (loss) before extraordinary items	103,762	147,562	(17,691)	(13)		103,749
Extraordinary items - loss on early extinguishment of debt	(3,753)	-	-	-		(3,753)
Net income (loss)	100,009	147,562	(17,691)	(13)		99,996
Other comprehensive income:						
Deferred hedge gains, net:						
Transition adjustment	-	(172,007)	(25,437)	-		(197,444)
Deferred hedge gains (losses)	(578)	364,051	29,531	-		393,004
Net (gains) losses included in net income	135	(8,595)	13,946	-		5,486
Gains and losses on available for sale securities:						
Unrealized holdings losses	-	(45)	-	-		(45)
Gains included in net income	-	(8,109)	-	-		(8,109)
Translation adjustment	-	-	(11,173)	-		(11,173)
Comprehensive income	$ 99,566	$ 322,857	$ (10,824)	$ (13)		$ 281,715

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Year Ended December 31, 2000
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues and other income:						
Oil and gas	$ -	$ 616,030	$ 236,708	$ -	$	$ 852,738
Interest and other	29	13,808	11,938	-		25,775
Gain (loss) on disposition of assets, net	(6,172)	36,946	3,410	-		34,184
	(6,143)	666,784	252,056	-		912,697
Costs and expenses:						
Oil and gas production	-	150,281	38,984	-		189,265
Depletion, depreciation and amortization	-	129,996	84,942	-		214,938
Exploration and abandonments	-	43,938	43,612	-		87,550
General and administrative	283	22,519	10,460	-		33,262
Interest	(53,180)	151,026	64,106	-		161,952
Equity (income) loss from subsidiary	(117,704)	(6,313)	-	-	124,017	-

Other................................	-	63,459	3,772	-	67,231
	(170,601)	554,906	245,876	-	754,198
Income before income taxes.............	164,458	111,878	6,180	-	158,499
Income tax benefit (provision)..........	-	(4)	5,963	41	6,000
Income before extraordinary item........	164,458	111,874	12,143	41	164,499
Extraordinary item - loss on early extinguishment of debt...............	(12,318)	-	-	-	(12,318)
Net income.............................	152,140	111,874	12,143	41	152,181
Other comprehensive income (loss):					
Unrealized gains on available for sale securities:					
Unrealized holdings gains...........	-	33,828	-	-	33,828
Gains included in net income........	-	(25,674)	-	-	(25,674)
Translation adjustment................	-	-	(6,910)	-	(6,910)
Comprehensive income...................	$ 152,140	$ 120,028	$ 5,233	$ 41	$ 153,425

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2002
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by (used in) operating activities......	$ (327,185)	$ 406,939	$ 252,491	$ 332,245
Cash flows from investing activities:				
Proceeds from disposition of assets.....................	31,994	86,703	153	118,850
Additions to oil and gas properties.....................	-	(365,981)	(248,717)	(614,698)
Other property (additions) retirements, net.............	-	(13,171)	888	(12,283)
Net cash provided by (used in) investing activities..	31,994	(292,449)	(247,676)	(508,131)
Cash flows from financing activities:				
Borrowings under long-term debt.........................	529,805	-	-	529,805
Principal payments on long-term debt....................	(481,783)	-	-	(481,783)
Issuance of common stock................................	236,000	-	-	236,000
Payments of noncurrent liabilities......................	-	(123,607)	(638)	(124,245)
Deferred loan fees/issuance costs.......................	(3,293)	-	-	(3,293)
Exercise of stock options and employee stock purchases...	14,389	-	-	14,389
Net cash provided by (used in) financing activities..	295,118	(123,607)	(638)	170,873
Net increase (decrease) in cash and cash equivalents.......	(73)	(9,117)	4,177	(5,013)
Effect of exchange rate changes on cash and cash equivalents...	-	-	(831)	(831)
Cash and cash equivalents, beginning of period............	79	10,900	3,355	14,334
Cash and cash equivalents, end of period..................	$ 6	$ 1,783	$ 6,701	$ 8,490

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2001
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by (used in) operating activities......	$ (10,503)	$ 307,776	$ 178,327	$ 475,600

Cash flows from investing activities:				
Cash acquired in acquisition, net of fees paid	-	11,119	-	11,119
Proceeds from disposition of assets	21,170	75,816	16,467	113,453
Additions to oil and gas properties	-	(336,753)	(192,970)	(529,723)
Other property additions, net	-	(10,717)	(6,873)	(17,590)
Net cash provided by (used in) investing activities	21,170	(260,535)	(183,376)	(422,741)
Cash flows from financing activities:				
Borrowings under long-term debt	328,331	-	-	328,331
Principal payments on long-term debt	(333,410)	-	-	(333,410)
(Payments of) borrowings under noncurrent liabilities	-	(54,728)	1,291	(53,437)
Purchase of treasury stock	(13,028)	-	-	(13,028)
Exercise of stock options and employee stock purchases	7,504	-	-	7,504
Net cash provided by (used in) financing activities	(10,603)	(54,728)	1,291	(64,040)
Net increase (decrease) in cash and cash equivalents	64	(7,487)	(3,758)	(11,181)
Effect of exchange rate changes on cash and cash equivalents	-	-	(644)	(644)
Cash and cash equivalents, beginning of period	15	18,387	7,757	26,159
Cash and cash equivalents, end of period	$ 79	$ 10,900	$ 3,355	$ 14,334

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001, 2000 and 1999

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2000
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by operating activities	$ 213,491	$ 118,300	$ 98,305	$ 430,096
Cash flows from investing activities:				
Proceeds from disposition of assets	-	92,342	10,394	102,736
Additions to oil and gas properties	-	(179,861)	(119,821)	(299,682)
Other property (additions) dispositions, net	-	(10,004)	12,449	2,445
Net cash used in investing activities	-	(97,523)	(96,978)	(194,501)
Cash flows from financing activities:				
Borrowings under long-term debt	922,607	-	-	922,607
Principal payments on long-term debt	(1,099,107)	(828)	-	(1,099,935)
Payment of noncurrent liabilities	-	(24,261)	(5,498)	(29,759)
Purchase of treasury stock	(27,298)	-	-	(27,298)
Deferred loan fees/issuance costs	(13,847)	-	-	(13,847)
Exercise of stock options and employee stock purchases	4,164	-	-	4,164
Net cash used in financing activities	(213,481)	(25,089)	(5,498)	(244,068)
Net increase (decrease) in cash and cash equivalents	10	(4,312)	(4,171)	(8,473)
Effect of exchange rate changes on cash and cash equivalents	-	-	(156)	(156)
Cash and cash equivalents, beginning of period	5	22,699	12,084	34,788
Cash and cash equivalents, end of period	$ 15	$ 18,387	$ 7,757	$ 26,159

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Capitalized Costs

	December 31, 2002	December 31, 2001
	(in thousands)	
Oil and Gas Properties:		
Proved	$ 4,252,897	$ 3,691,783
Unproved	219,073	187,785
	4,471,970	3,879,568
Less accumulated depletion	(1,303,541)	(1,095,310)
Net capitalized costs for oil and gas properties	$ 3,168,429	$ 2,784,258

Costs Incurred for Oil and Gas Producing Activities

	Property Acquisition Costs				
	Proved	Unproved	Exploration Costs	Development Costs	Total Costs Incurred
			(in thousands)		
Year Ended December 31, 2002:					
United States	$ 156,736	$ 34,048	$ 72,831	$ 269,945	$ 533,560
Argentina	12	51	14,530	20,528	35,121
Canada	457	2,329	9,992	20,728	33,506
South Africa	-	-	2,789	34,300	37,089
Gabon	-	-	23,585	-	23,585
Tunisia	-	1,843	6,320	-	8,163
Other foreign	-	-	1,431	-	1,431
Total costs incurred	$ 157,205	$ 38,271	$ 131,478	$ 345,501	$ 672,455
Year Ended December 31, 2001:					
United States	$ 132,793	$ 19,572	$ 129,639	$ 172,225	$ 454,229
Argentina	13,182	2,465	36,237	46,427	98,311
Canada	29	97	12,707	23,215	36,048
South Africa	706	125	21,936	13,860	36,627
Gabon	-	-	11,387	-	11,387
Tunisia	-	1,835	3,652	-	5,487
Other foreign	-	-	4,471	-	4,471
Total costs incurred	$ 146,710	$ 24,094	$ 220,029	$ 255,727	$ 646,560
Year Ended December 31, 2000:					
United States	$ 26,102	$ 28,199	$ 65,023	$ 84,798	$ 204,122
Argentina	1,169	520	35,406	31,335	68,430
Canada	8,709	2,506	6,744	25,632	43,591
South Africa	-	-	20,176	-	20,176
Gabon	-	-	1,326	-	1,326
Other foreign	-	-	2,095	-	2,095
Total costs incurred	$ 35,980	$ 31,225	$ 130,770	$ 141,765	$ 339,740

Results of Operations

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

Reserve Quantity Information

The estimates of the Company's proved oil and gas reserves as of December 31, 2002, which are located principally in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations 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. The estimates of the Company's proved oil and gas reserves as of December 31, 2001 and 2000 were prepared by the Company's engineers. Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, 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 reserve estimates for 2002, 2001 and 2000 utilize respective oil prices of $29.67, $18.88 and $25.71 per Bbl (reflecting adjustments for oil quality); respective NGL prices of $19.01, $11.58 and $16.74 per Bbl; and, respective gas prices of $3.37, $2.21 and $7.50 per Mcf (reflecting adjustments for Btu content, gas processing and shrinkage).

Oil and gas 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 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.

Oil and Gas Producing Activities:

	2002			2001			2000		
Total Proved Reserves:	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE
UNITED STATES									
Balance, January 1	279,146	1,474,090	524,829	266,802	1,354,327	492,523	259,066	1,314,842	478,206
Revisions of previous estimates	61,529	5,983	62,525	(1,179)	41,039	5,661	19,295	63,912	29,947
Purchases of minerals-in-place	8,634	83,361	22,528	24,943	63,113	35,462	1,237	28,071	5,916
New discoveries and extensions	4,364	5,349	5,255	4,442	93,220	19,979	4,819	66,486	15,900
Production	(16,042)	(84,812)	(30,177)	(15,862)	(77,609)	(28,796)	(16,872)	(83,930)	(30,860)
Sales of minerals-in-place	-	-	-	-	-	-	(743)	(35,054)	(6,586)
Balance, December 31	337,631	1,483,971	584,960	279,146	1,474,090	524,829	266,802	1,354,327	492,523
ARGENTINA									
Balance, January 1	35,669	471,150	114,193	35,843	408,282	103,890	29,797	415,620	99,067
Revisions of previous estimates	(4,954)	47,829	3,017	(932)	4,460	(189)	1,411	(15,558)	(1,182)
Purchases of minerals-in-place	-	-	-	170	31,700	5,453	-	-	-
New discoveries and extensions	3,985	41,652	10,927	4,354	58,538	14,110	8,066	43,914	15,385
Production	(3,168)	(28,550)	(7,926)	(3,766)	(31,830)	(9,071)	(3,431)	(35,694)	(9,380)
Balance, December 31	31,532	532,081	120,211	35,669	471,150	114,193	35,843	408,282	103,890
CANADA									
Balance, January 1	2,659	132,061	24,669	4,066	132,919	26,219	3,970	145,251	28,179
Revisions of previous estimates	24	(1,150)	(167)	212	15,067	2,723	429	(10,013)	(1,240)
Purchases of minerals-in-place	-	-	-	-	-	-	140	7,768	1,435

New discoveries and extensions...	68	6,070	1,080	81	5,644	1,022	138	6,132	1,160
Production......................	(390)	(17,653)	(3,333)	(671)	(18,426)	(3,742)	(611)	(16,219)	(3,315)
Sales of minerals-in-place.......	-	-	-	(1,029)	(3,143)	(1,553)	-	-	-
Balance, December 31............	2,361	119,328	22,249	2,659	132,061	24,669	4,066	132,919	26,219
SOUTH AFRICA									
Balance, January 1..............	7,685	-	7,685	5,552	-	5,552	-	-	-
Revisions of previous estimates..	790	-	790	-	-	-	-	-	-
Purchases of minerals-in-place...	-	-	-	2,133	-	2,133	-	-	-
New discoveries and extensions...	-	-	-	-	-	-	5,552	-	5,552
Balance, December 31............	8,475	-	8,475	7,685	-	7,685	5,552	-	5,552
TUNISIA									
Balance, January 1..............	-	-	-	-	-	-	-	-	-
New discoveries and extensions...	845	-	845	-	-	-	-	-	-
Balance, December 31............	845	-	845	-	-	-	-	-	-
TOTAL									
Balance, January 1..............	325,159	2,077,301	671,376	312,263	1,895,528	628,184	292,833	1,875,713	605,452
Revisions of previous estimates (a).................	57,389	52,662	66,165	(1,899)	60,566	8,195	21,135	38,341	27,525
Purchases of minerals-in-place...	8,634	83,361	22,528	27,246	94,813	43,048	1,377	35,839	7,351
New discoveries and extensions...	9,262	53,071	18,107	8,877	157,402	35,111	18,575	116,532	37,997
Production......................	(19,600)	(131,015)	(41,436)	(20,299)	(127,865)	(41,609)	(20,914)	(135,843)	(43,555)
Sales of minerals-in-place.......	-	-	-	(1,029)	(3,143)	(1,553)	(743)	(35,054)	(6,586)
Balance, December 31............	380,844	2,135,380	736,740	325,159	2,077,301	671,376	312,263	1,895,528	628,184
Proved Developed Reserves:									
United States.................	196,893	1,027,750	368,184	206,922	1,081,592	387,188	209,636	1,118,976	396,133
Argentina.....................	28,248	341,967	85,243	22,679	345,281	80,226	22,931	358,124	82,618
Canada........................	2,086	94,607	17,854	2,930	80,953	16,422	2,598	61,210	12,800
January 1...................	227,227	1,464,324	471,281	232,531	1,507,826	483,836	235,165	1,538,310	491,551
United States.................	209,948	1,067,701	387,899	196,893	1,027,750	368,184	206,922	1,081,592	387,188
Argentina.....................	22,180	402,640	89,287	28,248	341,967	85,243	22,679	345,281	80,226
Canada........................	2,042	90,003	17,042	2,086	94,607	17,854	2,930	80,953	16,422
December 31.................	234,170	1,560,344	494,228	227,227	1,464,324	471,281	232,531	1,507,826	483,836

<FN>

(a) The revisions of previous estimates above, include revisions attributable to changes in commodity prices totaling a 28,643 MBOE increase, a 24,970 MBOE decrease and a 14,009 MBOE increase for the years ended December 31, 2002, 2001 and 2000, respectively.

</FN>

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas 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 10 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 net cash flows estimated in the table below do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2002 commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge contracts discounted at 10 percent was a liability equal to approximately $226 million.

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 oil and gas 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.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

	For the Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
UNITED STATES Oil and gas producing activities:			
Future cash inflows	$15,161,717	$ 8,222,573	$18,660,169
Future production costs	(4,830,294)	(3,231,730)	(4,907,134)
Future development costs	(864,386)	(735,984)	(479,290)
Future income tax expense	(2,325,946)	(598,612)	(3,777,157)
	7,141,091	3,656,247	9,496,588
10% annual discount factor	(3,684,400)	(1,691,118)	(4,780,133)
Standardized measure of discounted future cash flows	$ 3,456,691	$ 1,965,129	$ 4,716,455
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 986,716	$ 1,070,664	$ 1,183,652
Future production costs	(175,938)	(227,435)	(215,853)
Future development costs	(84,669)	(144,604)	(114,606)
Future income tax expense	(143,845)	(45,140)	(81,705)
	582,264	653,485	771,488
10% annual discount factor	(242,158)	(262,334)	(264,126)
Standardized measure of discounted future cash flows	$ 340,106	$ 391,151	$ 507,362
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 502,260	$ 301,002	$ 1,029,007
Future production costs	(89,246)	(73,601)	(104,189)
Future development costs	(22,294)	(27,050)	(35,443)
Future income tax expense	(87,363)	(10,771)	(306,399)
	303,357	189,580	582,976
10% annual discount factor	(104,345)	(59,995)	(168,441)
Standardized measure of discounted future cash flows	$ 199,012	$ 129,585	$ 414,535
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 256,436	$ 149,777	$ 126,134
Future production costs	(92,820)	(73,697)	(65,232)
Future development costs	(23,200)	(54,281)	(47,970)
Future income tax expense	(4,465)	-	-
	135,951	21,799	12,932
10% annual discount factor	(14,588)	(7,338)	(5,782)
Standardized measure of discounted future cash flows	$ 121,363	$ 14,461	$ 7,150
TUNISIA			
Oil and gas producing activities:			
Future cash inflows	$ 23,460	$ -	$ -
Future production costs	(2,396)	-	-
Future development costs	(3,570)	-	-
Future income tax expense	(6,447)	-	-
	11,047	-	-
10% annual discount factor	(1,667)	-	-
Standardized measure of discounted future cash flows	$ 9,380	$ -	$ -

TOTAL
Oil and gas producing activities:

Future cash inflows	$16,930,589	$ 9,744,016	$20,998,962
Future production costs	(5,190,694)	(3,606,463)	(5,292,408)
Future development costs	(998,119)	(961,919)	(677,309)
Future income tax expense	(2,568,066)	(654,523)	(4,165,261)
	8,173,710	4,521,111	10,863,984
10% annual discount factor	(4,047,158)	(2,020,785)	(5,218,482)
Standardized measure of discounted future cash flows	$ 4,126,552	$ 2,500,326	$ 5,645,502

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Oil and Gas Producing Activities	For the Year Ended December 31, 2002	2001	2000
			(in thousands)
Oil and gas sales, net of production costs	$ (489,338)	$ (631,365)	$ (663,473)
Net changes in prices and production costs	2,042,575	(4,528,168)	3,829,794
Extensions and discoveries	152,253	184,454	525,361
Development costs incurred during the period	262,469	239,156	101,350
Sales of minerals-in-place	-	(23,372)	(72,624)
Purchases of minerals-in-place	187,460	201,535	187,097
Revisions of estimated future development costs	(387,404)	(429,365)	(200,734)
Revisions of previous quantity estimates	527,987	40,771	344,454
Accretion of discount	250,033	701,943	293,726
Changes in production rates, timing and other	99,722	(274,689)	(262,784)
Change in present value of future net revenues	2,645,757	(4,519,100)	4,082,167
Net change in present value of future income taxes	(1,019,531)	1,373,924	(1,373,924)
	1,626,226	(3,145,176)	2,708,243
Balance, beginning of year	2,500,326	5,645,502	2,937,259
Balance, end of year	$4,126,552	$ 2,500,326	$ 5,645,502

Selected Quarterly Financial Results

	Quarter First	Second	Third	Fourth
	(in thousands, except per share data)			
2002				
Operating revenues	$ 165,539	$ 172,430	$ 168,317	$ 195,494
Total revenues and other income	$ 166,658	$ 174,338	$ 178,753	$ 197,685
Costs and expenses	$ 169,027	$ 158,916	$ 157,953	$ 177,416
Net income (loss):				
Before extraordinary items	$ (1,959)	$ 13,985	$ 18,611	$ 18,422
Extraordinary items, net of tax (a)	-	(2,843)	(19,501)	(2)
Net income (loss)	$ (1,959)	$ 11,142	$ (890)	$ 18,420
Net income (loss) per share:				
Basic:				
Before extraordinary items	$ (.02)	$ .13	$ .16	$ .16
Extraordinary items	-	(.03)	(.17)	-

Net income (loss)	$ (.02)	$ .10	$ (.01)	$ .16
Diluted:				
Before extraordinary items	$ (.02)	$ .12	$ .16	$ .16
Extraordinary items	-	(.02)	(.17)	-
Net income (loss)	$ (,02)	$ .10	$ (.01)	$ .16
2001				
Operating revenues	$ 257,986	$ 218,611	$ 198,088	$ 172,337
Total revenues	$ 270,446	$ 231,038	$ 204,471	$ 170,526
Costs and expenses	$ 202,127	$ 200,092	$ 178,864	$ 187,633
Net income (loss):				
Before extraordinary items	$ 67,919	$ 28,338	$ 23,228	$ (15,736)
Extraordinary items, net of tax (a)	-	-	1,374	(5,127)
Net income (loss)	$ 67,919	$ 28,338	$ 24,602	$ (20,863)
Net income (loss) per share:				
Basic:				
Before extraordinary items	$ .69	$ .29	$ .24	$ (.16)
Extraordinary items	-	-	.01	(.05)
Net income (loss)	$ .69	$ .29	$ .25	$ (.21)
Diluted:				
Before extraordinary items	$ .68	$ .28	$ .24	$ (.16)
Extraordinary items	-	-	.01	(.05)
Net income (loss)	$ .68	$ .28	$ .25	$ (.21)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 15, 2003 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 15, 2003 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 15, 2003 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 15, 2003 and is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

(a) Evaluation of disclosure controls and procedures. Within 90 days prior to the filing date of this Report, the Company's principal executive officer ("CEO") and principal financial officer ("CFO") carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures. Based on those evaluations, the Company's CEO and CFO believe (i) that the Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that such information is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and (ii) that the Company's disclosure controls and procedures are effective.

(b) Changes in internal controls. There have been no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to the evaluation referred to in Item 14. (a), above, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) Listing of Financial Statements and Exhibits

Financial Statements

The following consolidated financial statements of the Company are included in "Item 8. Financial Statements and Supplementary Data":

Independent Auditors' Report
Consolidated Balance Sheets as of December 31, 2002 and 2001
Consolidated Statements of Operations for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2002, 2001 and 2000
Notes to Consolidated Financial Statements
Unaudited Supplementary Information

(b) Reports on Form 8-K

During the three months ended December 31, 2002, the Company filed one Current Report on Form 8-K dated October 24, 2002. The Company's October 24, 2002 Form 8-K provided, under Items 7 and 9, (i) the Company's news release dated October 24, 2002 that announced the Company's financial and operating results for the three and nine month periods ended September 30, 2002, an operational update and the Company's fourth quarter 2002 financial outlook; and (ii) tables summarizing, as of October 23, 2002, the Company's open oil hedge positions, open gas hedge positions and deferred hedge gains and losses on terminated commodity hedges.

(c) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(c) are listed below and in the "Index to Exhibits" attached hereto.

(d) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

Exhibits

Exhibit Number		Description
3.1	-	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).
3.2	-	Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).
3.3	-	Certificate of Designation of Series A Junior Participating Preferred Stock (incorporated by reference to Exhibit A to Exhibit 4.1 to the Company's Registration Statement on Form 8-A, File No. 001-13245, filed with the SEC on July 24, 2001).
4.1	-	Form of Certificate of Common Stock, par value $.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).
4.2	-	Rights Agreement dated July 24, 2001, between the Company and Continental Stock Transfer & Trust Company, as Rights Agent (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form 8-A, File No. 001-13245, filed with the SEC on July 24, 2001).
10.1	-	Indenture, dated April 12, 1995, between Pioneer USA (successor to Parker & Parsley Petroleum Company ("Parker & Parsley")), and The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4.1 to Parker & Parsley's Current Report on Form 8-K, dated April 12, 1995, File No. 001-10695).
10.2	-	First Supplemental Indenture, dated as of August 7, 1997, among Parker & Parsley, The Chase Manhattan Bank, as Trustee, and Pioneer USA, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).
10.3	-	Second Supplemental Indenture, dated as of December 30, 1997, among Pioneer USA, a Delaware corporation, Pioneer NewSub1, Inc., a Texas corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.17 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).
10.4	-	Third Supplemental Indenture, dated as of December 30, 1997, among Pioneer NewSub1, Inc. (as successor to Pioneer USA), a Texas corporation, Pioneer DebtCo, Inc., a Texas corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.18 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).
10.5	-	Fourth Supplemental Indenture, dated as of December 30, 1997, among Pioneer DebtCo, Inc. (as successor to Pioneer NewSub1, Inc., as successor to Pioneer USA), a Texas corporation, the Company, a Delaware corporation, Pioneer USA, a Delaware corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.19 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).

Exhibit Number		Description
10.6	-	Guarantee, dated as of December 30, 1997, by Pioneer USA relating to the $150,000,000 in aggregate principal amount of 8-7/8% Senior Notes due 2005 and $150,000,000 in aggregate principal amount of 8-1/4% Senior Notes due 2007 issued under the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.20 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).
10.7	-	Form of 8-7/8% Senior Notes Due 2005, dated as of April 12, 1995, in the aggregate principal amount of $150,000,000, together with Officers' Certificate dated April 12, 1995, establishing the terms of the 8-7/8% Senior Notes Due 2005 pursuant to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 4.2 to Parker & Parsley's Quarterly Report on Form 10-Q for the period ended June 30, 1995, File No. 001-10695).
10.8	-	Form of 8-1/4% Senior Notes due 2007, dated as of August 22, 1995, in the aggregate principal amount of $150,000,000, together with Officers' Certificate dated August 22, 1995, establishing the terms of the 8-1/4% Senior Notes due 2007 pursuant to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 1.2 to Parker & Parsley's Current Report on Form 8-K, dated August 17, 1995, File No. 001-10695).
10.9	-	Indenture, dated January 13, 1998, between the Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 99.1 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.10	-	First Supplemental Indenture, dated as of January 13, 1998, among the Company, Pioneer USA, as the Subsidiary Guarantor, and The Bank of New York, as Trustee, with respect to the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.2 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.11	-	Form of 6.50% Senior Notes Due 2008 of the Company (incorporated by reference to Exhibit 99.3 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.12	-	Form of 7.20% Senior Notes Due 2028 of the Company (incorporated by reference to Exhibit 99.4 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.13	-	Guarantee dated as of January 13, 1998, by Pioneer USA relating to the $350,000,000 in aggregate principal amount of 6.50% Senior Notes Due 2008 issued under the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.5 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.14	-	Guarantee dated as of January 13, 1998, by Pioneer USA relating to the $250,000,000 in aggregate principal amount of 7.20% Senior Notes Due 2028 issued under the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.6 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).
10.15H	-	1991 Stock Option Plan of Mesa Inc. ("Mesa") (incorporated by reference to Exhibit 10(v) to Mesa's Annual Report on Form 10-K for the period ended December 31, 1991).
10.16H	-	1996 Incentive Plan of Mesa (incorporated by reference to Exhibit

10.28 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).

10.17H - Parker & Parsley Long-Term Incentive Plan, dated February 19, 1991 (incorporated by reference to Exhibit 4.1 to Parker & Parsley's Registration Statement on Form S-8, Registration No. 33-38971).

Exhibit Number		Description
10.18H	-	First Amendment to the Parker & Parsley Long-Term Incentive Plan, dated August 23, 1991 (incorporated by reference to Exhibit 10.2 to Parker & Parsley's Registration Statement on Form S-1, dated February 28, 1992, Registration No. 33-46082).
10.19H	-	The Company's Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-35087).
10.20H	-	First Amendment to the Company's Long-Term Incentive Plan, effective as of November 23, 1998 (incorporated by reference to Exhibit 10.72 to the Company's Annual Report on Form 10-K for the period ended December 31, 1999, File No. 1-13245).
10.21H	-	Second Amendment to the Company's Long-Term Incentive Plan, effective as of May 20, 1999 (incorporated by reference to Exhibit 10.73 to the Company's Annual Report on Form 10-K for the period ended December 31, 1999, File No. 1-13245).
10.22H	-	Third Amendment to the Company's Long-Term Incentive Plan, effective as of February 17, 2000 (incorporated by reference to Exhibit 10.76 to the Company's Annual Report on Form 10-K for the period ended December 31, 1999, File No. 1-13245).
10.23H	-	The Company's Employee Stock Purchase Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-35165).
10.24H	-	First Amendment to the Company's Employee Stock Purchase Plan, dated December 9, 1998 (incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-13245).
10.25H	-	Second Amendment to the Company's Employee Stock Purchase Plan, dated December 14, 1999 (incorporated by reference to Exhibit 10.74 to the Company's Annual Report on Form 10-K for the period ended December 31, 1999, File No. 1-13245).
10.26H	-	The Company's Deferred Compensation Retirement Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-39153).
10.27H	-	Omnibus Amendment to Nonstatutory Stock Option Agreements, included as part of the Parker & Parsley Long-Term Incentive Plan, dated as of November 16, 1995, between Parker & Parsley and Named Executive Officers identified on Schedule 1 setting forth additional details relating to the Parker & Parsley Long-Term Incentive Plan (incorporated by reference to Parker & Parsley's Annual Report on Form 10-K for the year ended December 31, 1995, File No. 001-10695).
10.28H	-	Severance Agreement, dated as of August 8, 1997, between the Company and Scott D. Sheffield, together with a schedule identifying substantially identical agreements between the Company and each of the other named executive officers identified on Schedule I for the purpose of defining the payment of certain benefits upon the termination of the officer's employment under certain circumstances

(incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).

10.29H - Indemnification Agreement, dated as of August 8, 1997, between the Company and Scott D. Sheffield, together with a schedule identifying substantially identical agreements between the Company and each of the Company's other directors and named executive officers identified on Schedule I (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).

10.30H* - Pioneer USA 401(k) and Matching Plan, Amended and Restated Effective as of January 1, 2002.

Exhibit Number		Description
10.31	-	Second Supplemental Indenture, dated as of April 11, 2000, among the Company, Pioneer USA, as the subsidiary guarantor and the Bank of New York, as trustee, with respect to the Indenture, dated January 13, 1998, between the Company and The Bank of New York, as trustee (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).
10.32	-	Form of 9-5/8% Senior Notes Due 2010, dated as of April 11, 2000, in the aggregate principal amount of $425,000,000, together with Trustee's Certificate of Authentication dated April 11, 2000, establishing the terms of the 9-5/8% Senior Notes Due April 1, 2010 pursuant to the Second Supplemental Indenture identified above as Exhibit 10.31 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).
10.33	-	Guarantee, dated as of April 11, 2000, by Pioneer USA as the subsidiary guarantor relating to the $425,000,000 aggregate principal amount of 9-5/8% Senior Notes Due April 1, 2010 issued under the Second Supplemental Indenture identified above as Exhibit 10.31 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).
10.34	-	$575,000,000 Credit Agreement, dated as of May 31, 2000, among the Company, as the borrower, Bank of America, N.A., as the Administrative Agent, Credit Suisse First Boston, as the Documentation Agent, the Chase Manhattan Bank, as the Syndicated Agent and certain Lenders (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2000).
10.35	-	Agreement and Plan of Merger dated as of November 28, 2000 by and among the Company, Pioneer USA, Parker & Parsley Employees Producing Properties 87-A, Ltd., Parker & Parsley Employees Producing Properties 87-B Ltd., P&P Employees Producing Properties 88-A, L.P., P&P Employees 89-A Conv., L.P., P&P Employees 89-B Conv., L.P., P&P Employees Private 89, L.P., P&P Employees 90-A Conv., L.P., P&P Employees 90-B Conv., L.P., P&P Employees 90-C Conv., L.P., P&P Employees Private 90, L.P., P&P Employees 90 Spraberry Private Development, L.P., P&P Employees 91-A Conv., L.P. and P&P Employees 91-B Conv., L.P. (incorporated by reference to Exhibit 10.53 to the Company's Annual Report on Form 10-K for the period ended December 31, 2000, File No. 1-13245).
10.36	-	Agreement and Plan of Merger dated as of September 20, 2001, among the Company, Pioneer USA and the Parker & Parsley partnerships named therein (incorporated by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-4, Registration No. 333-59094, filed with the SEC on April 17, 2001).

10.37 - Underwriting Agreement dated April 16, 2002, among the Company, Pioneer USA and Credit Suisse First Boston Corporation (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 17, 2002).

10.38 - Terms Agreement dated April 16, 2002, among the Company, Pioneer USA, Credit Suisse First Boston Corporation, Banc of America Securities LLC, J.P. Morgan Securities Inc. and Lehman Brothers Inc. as representatives of the underwriters (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 17, 2002).

10.39 - Third Supplemental Indenture dated as of April 30, 2002, among the Company, Pioneer USA as the subsidiary guarantor and The Bank of New York, as Trustee (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2002, File No. 001-13245, filed with the SEC on May 14, 2002).

10.40 - Form of 7.50% Senior Notes Due 2012 of the Company (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 29, 2002).

Exhibit
Number Description

10.41 - Guarantee dated as of April 30, 2002, by Pioneer USA relating to the $150,000,000 in aggregate principal amount of 7.50% Senior Notes Due 2012 issued under the indenture identified above as Exhibit 10.39 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2002, File No. 001-13245, filed with the SEC on May 14, 2002).

21.1* - Subsidiaries of the registrant.

23.1* - Consent of Ernst & Young LLP.

23.2* - Consent of Netherland, Sewell & Associates, Inc.

23.3* - Consent of Gaffney, Cline & Associates, Inc.

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* Filed herewith

H Executive Compensation Plan or Arrangement previously filed pursuant to Item 14(c).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PIONEER NATURAL RESOURCES COMPANY

Date: February 20, 2003 By: /s/ Scott D. Sheffield

Scott D. Sheffield, Chairman of the Board, Chief

Executive Officer, President and Assistant Secretary

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Scott D. Sheffield ---------------------------- Scott D. Sheffield	Chairman of the Board, President, Chief Executive Officer and Assistant Secretary (principal executive officer)	February 20, 2003
/s/ Timothy L. Dove ---------------------------- Timothy L. Dove	Executive Vice President, Chief Financial Officer and Assistant Secretary	February 20, 2003
/s/ Richard P. Dealy ---------------------------- Richard P. Dealy	Vice President and Chief Accounting Officer	February 20, 2003
/s/ James R. Baroffio ---------------------------- James R. Baroffio	Director	February 20, 2003
/s/ Edison C. Buchanan ---------------------------- Edison C. Buchanan	Director	February 20, 2003
/s/ R. Hartwell Gardner ---------------------------- R. Hartwell Gardner	Director	February 20, 2003
/s/ James L. Houghton ---------------------------- James L. Houghton	Director	February 20, 2003
/s/ Jerry P. Jones ---------------------------- Jerry P. Jones	Director	February 20, 2003
/s/ Linda K. Lawson ---------------------------- Linda K. Lawson	Director	February 20, 2003
/s/ Charles E. Ramsey, Jr. ---------------------------- Charles E. Ramsey, Jr.	Director	February 20, 2003
/s/ Robert A. Solberg ---------------------------- Robert A. Solberg	Director	February 20, 2003

CERTIFICATIONS

I, Scott D. Sheffield, certify that:

1. I have reviewed this annual report on Form 10-K of Pioneer Natural Resources Company (the "Company"):

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and

6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

February 20, 2003

/s/ Scott D. Sheffield

Scott D. Sheffield, Chairman, President
and Chief Executive Officer

I, Timothy L. Dove, certify that:

1. I have reviewed this annual report on Form 10-K of Pioneer Natural Resources Company (the "Company"):

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make

the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Company and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the Company's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Company's ability to record, process, summarize and report financial data and have identified for the Company's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls; and

6. The Company's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

February 20, 2003

/s/ Timothy L. Dove

Timothy L. Dove, Executive Vice President
and Chief Financial Officer

Exhibit Index Page

3.1 - Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).

3.2 - Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).

3.3 - Certificate of Designation of Series A Junior Participating

Preferred Stock (incorporated by reference to Exhibit A to Exhibit 4.1 to the Company's Registration Statement on Form 8-A, File No. 001-13245, filed with the SEC on July 24, 2001).

4.1 - Form of Certificate of Common Stock, par value $.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).

4.2 - Rights Agreement dated July 24, 2001, between the Company and Continental Stock Transfer & Trust Company, as Rights Agent (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form 8-A, File No. 001-13245, filed with the SEC on July 24, 2001).

10.1 - Indenture, dated April 12, 1995, between Pioneer USA (successor to Parker & Parsley Petroleum Company ("Parker & Parsley")), and The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4.1 to Parker & Parsley's Current Report on Form 8-K, dated April 12, 1995, File No. 001-10695).

10.2 - First Supplemental Indenture, dated as of August 7, 1997, among Parker & Parsley, The Chase Manhattan Bank, as Trustee, and Pioneer USA, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).

10.3 - Second Supplemental Indenture, dated as of December 30, 1997, among Pioneer USA, a Delaware corporation, Pioneer NewSub1, Inc., a Texas corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.17 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).

10.4 - Third Supplemental Indenture, dated as of December 30, 1997, among Pioneer NewSub1, Inc.(as successor to Pioneer USA), a Texas corporation, Pioneer DebtCo, Inc., a Texas corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.18 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).

10.5 - Fourth Supplemental Indenture, dated as of December 30, 1997, among Pioneer DebtCo, Inc. (as successor to Pioneer NewSub1, Inc., as successor to Pioneer USA), a Texas corporation, the Company, a Delaware corporation, Pioneer USA, a Delaware corporation, and The Chase Manhattan Bank, a New York banking association, as Trustee, with respect to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.19 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 2, 1998).

10.6 - Guarantee, dated as of December 30, 1997, by Pioneer USA relating to the $150,000,000 in aggregate principal amount of 8-7/8% Senior Notes due 2005 and $150,000,000 in aggregate principal amount of 8-1/4% Senior Notes due 2007 issued under the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 10.20 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January

2, 1998).

10.7 - Form of 8-7/8% Senior Notes Due 2005, dated as of April 12, 1995, in the aggregate principal amount of $150,000,000, together with Officers' Certificate dated April 12, 1995, establishing the terms of the 8-7/8% Senior Notes Due 2005 pursuant to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 4.2 to Parker & Parsley's Quarterly Report on Form 10-Q for the period ended June 30, 1995, File No. 001-10695).

10.8 - Form of 8-1/4% Senior Notes due 2007, dated as of August 22, 1995, in the aggregate principal amount of $150,000,000, together with Officers' Certificate dated August 22, 1995, establishing the terms of the 8-1/4% Senior Notes due 2007 pursuant to the indenture identified above as Exhibit 10.1 (incorporated by reference to Exhibit 1.2 to Parker & Parsley's Current Report on Form 8-K, dated August 17, 1995, File No. 001-10695).

10.9 - Indenture, dated January 13, 1998, between the Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 99.1 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.10 - First Supplemental Indenture, dated as of January 13, 1998, among the Company, Pioneer USA, as the Subsidiary Guarantor, and The Bank of New York, as Trustee, with respect to the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.2 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.11 - Form of 6.50% Senior Notes Due 2008 of the Company (incorporated by reference to Exhibit 99.3 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.12 - Form of 7.20% Senior Notes Due 2028 of the Company (incorporated by reference to Exhibit 99.4 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.13 - Guarantee dated as of January 13, 1998, by Pioneer USA relating to the $350,000,000 in aggregate principal amount of 6.50% Senior Notes Due 2008 issued under the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.5 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.14 - Guarantee dated as of January 13, 1998, by Pioneer USA relating to the $250,000,000 in aggregate principal amount of 7.20% Senior Notes Due 2028 issued under the indenture identified above as Exhibit 10.9 (incorporated by reference to Exhibit 99.6 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on January 14, 1998).

10.15H - 1991 Stock Option Plan of Mesa Inc. ("Mesa") (incorporated by reference to Exhibit 10(v) to Mesa's Annual Report on Form 10-K for the period ended December 31, 1991).

10.16H - 1996 Incentive Plan of Mesa (incorporated by reference to Exhibit 10.28 to the Company's Registration Statement on Form S-4, dated June 27, 1997, Registration No. 333-26951).

10.17H - Parker & Parsley Long-Term Incentive Plan, dated February 19, 1991 (incorporated by reference to Exhibit 4.1 to Parker & Parsley's Registration Statement on Form S-8, Registration No. 33-38971).

10.18H - First Amendment to the Parker & Parsley Long-Term Incentive Plan, dated August 23, 1991 (incorporated by reference to Exhibit 10.2 to Parker & Parsley's Registration Statement on Form S-1, dated February 28, 1992, Registration No. 33-46082).

10.19H - The Company's Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-35087).

10.20H - First Amendment to the Company's Long-Term Incentive Plan, effective as of November 23, 1998 (incorporated by reference to Exhibit 10.72 to the Company's Annual Report on Form 10- K for the period ended December 31, 1999, File No. 1-13245).

10.21H - Second Amendment to the Company's Long-Term Incentive Plan, effective as of May 20, 1999 (incorporated by reference to Exhibit 10.73 to the Company's Annual Report on Form 10-K for the period ended December 31, 1999, File No. 1-13245).

10.22H - Third Amendment to the Company's Long-Term Incentive Plan, effective as of February 17, 2000 (incorporated by reference to Exhibit 10.76 to the Company's Annual Report on Form 10- K for the period ended December 31, 1999, File No. 1-13245).

10.23H - The Company's Employee Stock Purchase Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-35165).

10.24H - First Amendment to the Company's Employee Stock Purchase Plan, dated December 9, 1998 (incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-13245).

10.25H - Second Amendment to the Company's Employee Stock Purchase Plan, dated December 14, 1999 (incorporated by reference to Exhibit 10.74 to the Company's Annual Report on Form 10- K for the period ended December 31, 1999, File No. 1-13245).

10.26H - The Company's Deferred Compensation Retirement Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-39153).

10.27H - Omnibus Amendment to Nonstatutory Stock Option Agreements, included as part of the Parker & Parsley Long-Term Incentive Plan, dated as of November 16, 1995, between Parker & Parsley and Named Executive Officers identified on Schedule 1 setting forth additional details relating to the Parker & Parsley Long-Term Incentive Plan (incorporated by reference to Parker & Parsley's Annual Report on Form 10-K for the year ended December 31, 1995, File No. 001-10695).

10.28H - Severance Agreement, dated as of August 8, 1997, between the Company and Scott D. Sheffield, together with a schedule identifying substantially identical agreements between the Company and each of the other named executive officers identified on Schedule I for the purpose of defining the payment of certain benefits upon the termination of the officer's employment under certain circumstances (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).

10.29H - Indemnification Agreement, dated as of August 8, 1997, between the Company and Scott D. Sheffield, together with a schedule identifying substantially identical agreements between the Company and each of the Company's other directors and named executive officers identified on Schedule I (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1997, File No. 001-13245).

10.30H* - Pioneer USA 401(k) and Matching Plan, Amended and Restated Effective as of January 1, 2002.

10.31 - Second Supplemental Indenture, dated as of April 11, 2000, among the Company, Pioneer USA, as the subsidiary guarantor and the Bank of New York, as trustee, with respect to the Indenture, dated January 13, 1998, between the Company and The Bank of New York, as trustee (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).

10.32 - Form of 9-5/8% Senior Notes Due 2010, dated as of April 11, 2000, in the aggregate principal amount of $425,000,000, together with Trustee's Certificate of Authentication dated April 11, 2000, establishing the terms of the 9-5/8% Senior Notes Due April 1, 2010 pursuant to the Second Supplemental Indenture identified above as Exhibit 10.31 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).

10.33 - Guarantee, dated as of April 11, 2000, by Pioneer USA as the subsidiary guarantor relating to the $425,000,000 aggregate principal amount of 9-5/8% Senior Notes Due April 1, 2010 issued under the Second Supplemental Indenture identified above as Exhibit 10.31 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 11, 2000).

10.34 - $575,000,000 Credit Agreement, dated as of May 31, 2000, among the Company, as the borrower, Bank of America, N.A., as the Administrative Agent, Credit Suisse First Boston, as the Documentation Agent, the Chase Manhattan Bank, as the Syndicated Agent and certain Lenders (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on August 9, 2000).

10.35 - Agreement and Plan of Merger dated as of November 28, 2000 by and among the Company, Pioneer USA, Parker & Parsley Employees Producing Properties 87-A, Ltd., Parker & Parsley Employees Producing Properties 87-B Ltd., P&P Employees Producing Properties 88-A, L.P., P&P Employees 89-A Conv., L.P., P&P Employees 89-B Conv., L.P., P&P Employees Private 89, L.P., P&P Employees 90-A Conv., L.P., P&P Employees 90-B Conv., L.P., P&P Employees 90-C Conv., L.P., P&P Employees Private 90, L.P., P&P Employees 90 Spraberry Private Development, L.P., P&P Employees 91-A Conv., L.P. and P&P Employees 91-B Conv., L.P. (incorporated by reference to Exhibit 10.53 to the Company's Annual Report on Form 10-K for the period ended December 31, 2000, File No. 1-13245).

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10.36 - Agreement and Plan of Merger dated as of September 20, 2001, among the Company, Pioneer USA and the Parker & Parsley partnerships named therein (incorporated by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-4, Registration No. 333-59094, filed with the SEC on April 17, 2001).

10.37 - Underwriting Agreement dated April 16, 2002, among the Company, Pioneer USA and Credit Suisse First Boston Corporation (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 17, 2002).

10.38 - Terms Agreement dated April 16, 2002, among the Company, Pioneer USA, Credit Suisse First Boston Corporation, Banc of America Securities LLC, J.P. Morgan Securities Inc. and Lehman Brothers Inc. as representatives of the underwriters (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 17, 2002).

10.39 - Third Supplemental Indenture dated as of April 30, 2002, among the Company, Pioneer USA as the subsidiary guarantor and The Bank of New York, as Trustee (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2002, File No. 001-13245, filed with the SEC on May 14, 2002).

10.40 - Form of 7.50% Senior Notes Due 2012 of the Company (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K, File No. 001-13245, filed with the SEC on April 29, 2002).

10.41 - Guarantee dated as of April 30, 2002, by Pioneer USA relating to the $150,000,000 in aggregate principal amount of 7.50% Senior Notes Due 2012 issued under the indenture identified above as Exhibit 10.39 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2002, File No. 001-13245, filed with the SEC on May 14, 2002).

21.1* - Subsidiaries of the registrant.

23.1* - Consent of Ernst & Young LLP.

23.2* - Consent of Netherland, Sewell & Associates, Inc.

23.3* - Consent of Gaffney, Cline & Associates, Inc.

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* Filed herewith

H Executive Compensation Plan or Arrangement previously filed pursuant to Item 14(c).

EXHIBIT 10.30H

PIONEER NATURAL RESOURCES USA, INC.

401(k) AND MATCHING PLAN

(Amended and Restated Effective as of January 1, 2002)

PIONEER NATURAL RESOURCES USA, INC.
401(k) AND MATCHING PLAN

(Amended and Restated Effective as of January 1, 2002)

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PIONEER NATURAL RESOURCES USA, INC.
401(k) AND MATCHING PLAN

(Amended and Restated Effective as of January 1, 2002)

THIS 401(k) AND MATCHING PLAN, a profit sharing plan, made and executed by PIONEER NATURAL RESOURCES USA, INC., a Delaware corporation (the "Company"),

W I T N E S S E T H T H A T :

WHEREAS, the Company has heretofore maintained for the benefit of its employees a qualified profit sharing plan known as the Pioneer Natural Resources USA, Inc. 401(k) Plan and a qualified money purchase pension plan known as the Pioneer Natural Resources USA, Inc. Matching Plan; and

WHEREAS, effective as of 12:01 a.m. on January 1, 2002, the Company merged the Pioneer Natural Resources USA, Inc. Matching Plan with and into the Pioneer Natural Resources, Inc. 401(k) Plan; and

WHEREAS, the Company now desires to restate the Pioneer Natural Resources USA, Inc. 401(k) Plan to accommodate such merger, change the plan name, update the plan for tax compliance, incorporate prior amendments and make certain other changes;

NOW, THEREFORE, in consideration of the premises and pursuant to the authority reserved thereunder, the Pioneer Natural Resources USA, Inc. 401(k) Plan is hereby amended by restatement in its entirety, effective as of January 1, 2002, as the Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan to read as follows:

ARTICLE I.

DEFINITIONS AND CONSTRUCTION

Section 1.1 Definitions. Unless the context clearly indicates otherwise, when used in this Plan:

(a) "Account" means a Participant's After-Tax Account, Employer Employer Account, Matching Plan Account, Mesa After-Tax Account, Mesa Premium Account, Mesa Profit-Sharing Account, Pre-Tax Account, Prior Plan Employer Account, Prior Plan Pre-Tax Account and/or Rollover Account, as the context requires. The Committee may establish and maintain separate subaccounts within a Participant's Accounts if it deems such to be necessary for the proper administration of the Plan.

(b) "Affiliated Company" means any corporation or organization, other than an Employer, which is a member of a controlled group of corporations (within the meaning of Section 414(b) of the Code) or of an affiliated service group (within the meaning of Section 414(m) of the Code) with respect to which an Employer is also a member, and any other incorporated or unincorporated trade or business which along with an Employer is under common control (within the meaning of the regulations from time to time promulgated by the Secretary of the Treasury pursuant to Section 414(c) of the Code); provided, however, that for the purposes of Section 10.3 of the Plan, Section 414(b) and (c) of the Code shall be applied as modified by Section 415(h) of the Code.

(c) "After-Tax Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to After-Tax Contributions made to this Plan.

(d) "After-Tax Contribution" means a contribution made by a Participant to this Plan pursuant to Section 3.4.

(e) "Basic Compensation" means the sum of (i) the base salary or wages and any overtime payable by an Employer to an Employee for personal services rendered to the Employer but excluding any amount payable pursuant to an Employer's salary continuation program, (ii) any contributions made by an Employer on behalf of the Employee to a qualified cash or deferred arrangement (within the meaning of Section 401(k) of the Code) maintained by such Employer, including any Catch-Up Contributions and Total Pre-Tax Contributions made by an Employer to this Plan on behalf of such Employee, (iii) any compensation reduction amounts elected by such Employee for the purchase of benefits pursuant to a cafeteria plan (within the meaning of Section 125(d) of the Code) maintained by an Employer, and (iv) any elective amounts that are not includible in the gross income of an Employee by reason of Section 132(f)(4) of the Code; provided, however, that the Basic Compensation of an Employee taken into account under the Plan for any Plan Year shall not exceed $200,000 (as adjusted to take into account any cost-of-living increases authorized pursuant to Section 401(a)(17)(B) of the Code).

(f) "Catch-Up Contribution" means a pre-tax contribution made by an Employer on behalf of a Participant pursuant to Section 3.3.

(g) "Code" means the Internal Revenue Code of 1986, as amended.

(h) "Committee" means the 401(k) and Matching Plan Committee appointed by the Board of Directors of the Company to administer the Plan.

(i) "Company" means Pioneer Natural Resources USA, Inc., a Delaware corporation, and any successor thereto.

(j) "Compensation" means the sum of (i) wages within the meaning of Section 3401(a) of the Code and all other payments of remuneration to an Employee by an Employer (in the course of the Employer's trade or business) for which the Employer is required to furnish the Employee a written statement under Sections 6041(d), 6051(a)(3) and 6052 of the Code, but determined without regard to any rules that limit the remuneration included in wages based on the nature or location of the employment or the services performed (such as the exception for agricultural labor in Section 3401(a)(2) of the Code), (ii) any contributions made by an Employer on behalf of the Employee to a qualified cash or deferred arrangement (within the meaning of Section 401(k) of the Code) maintained by such Employer, including any Catch-Up Contributions and Total Pre-Tax Contributions made by an Employer to this Plan on behalf of such Employee, (iii) any compensation reduction amounts elected by such Employee for the purchase of benefits pursuant to a cafeteria plan (within the meaning of Section 125(d) of the Code) maintained by an Employer, and (iv) any elective amounts that are not includible in the gross income of an Employee by reason of Section 132(f)(4) of the Code; provided, however, that except for purposes of determining whether an Employee is a Highly Compensated Employee or a Key Employee (within the meaning of Section 9.1(c)), the Compensation of an Employee taken into account under the Plan for any Plan Year shall not exceed $200,000 (as adjusted to take into account any cost-of-living increases authorized pursuant to Section 401(a)(17)(B) of the Code).

(k) "Covered Employee" means any Employee other than an individual who is (i) a member of a collective bargaining unit with which an Employer negotiates and with respect to whom no coverage under this Plan has been provided by collective bargaining agreement, (ii) a nonresident alien with respect to the United States who receives no earned income from an Employer which constitutes income from sources within the United States, (iii) a temporary or seasonal Employee as determined in accordance with the Employer's normal personnel policies, (iv) not treated by an Employer at the time of the performance of services as an employee for federal tax purposes, regardless of any subsequent reclassification by an Employer, any governmental agency or account, or (v) treated as a leased employee by an Employer.

(l) "Employee" means any individual employed by an Employer.

(m) "Employer" shall include the Company and a ny other incorporated or unincorporated trade or business which may subsequently adopt this Plan with the consent of the Board of Directors of the Company.

(n) "Employer Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to (i) any amounts credited to his or her Employer Account under the Superseded Plan as in effect on December 31, 2001, and (ii) any Matching Contributions made to the Plan for the Participant on or after January 1, 2002.

(o) "Employment Date" means the date an Employee first performs an Hour of Service.

(p) "Highly Compensated Employee" means for a Plan Year:

(1) any Employee who during such Plan Year or during the preceding Plan Year was at any time a 5-percent owner (as defined in Section 416(i)(1) of the Code) of an Employer or Affiliated Company; or

(2) any Employee who during the preceding Plan Year received Compensation greater than $80,000 (as adjusted to take into account any cost-of-living increases authorized pursuant to Section 414(q)(1) of the Code) and who is in the group consisting of the top 20% (when ranked on the basis of Compensation received during such preceding year) of all Employees, except those excluded pursuant to Section 414(q)(5) of the Code.

Solely for purposes of this definition, (i) an employee of an Affiliated Company shall be deemed to be an Employee, (ii) compensation received from an Affiliated Company shall be deemed to be Compensation, and (iii) a nonresident alien who receives no earned income from an Employer or Affiliated Company which constitutes income from sources within the United States shall not be considered an Employee.

(q) "Hour of Service" means an hour for which an Employee is directly or indirectly compensated or entitled to compensation (including back pay, regardless of mitigation of damages) by an Employer for the performance of duties for an Employer or for reasons (such as vacation, sickness or disability) other than the performance of duties for an Employer. An Employee will be credited with eight Hours of Service per day for any customary work period during which such Employee is on leave of absence authorized by his or her Employer. Leaves of absence shall be granted by an Employer to its Employees on a uniform, nondiscriminatory basis. In no event shall more than 501 Hours of Service be credited on account of any single continuous period during which the individual performs no duties. An Employee's Hours of Service shall be credited to the appropriate Plan Years or eligibility computation period determined in accordance with the provisions of Section 2530.200b-2(b) and (c) of the Department of Labor Regulations, which are incorporated herein by this reference. In determining Hours of Service for the purposes of this Plan, periods of employment by an Affiliated Company and services performed as a leased employee (within the meaning of Section 414(n) of the Code) of an Employer or Affiliated Company shall be deemed to be periods of employment by an Employer.

(r) "Investment Fund" means any fund authorized for the investment of Trust assets pursuant to Section 4.2.

(s) "Matching Contribution" means a contribution made by an Employer to the Plan for a Participant pursuant to Section 3.2.

(t) "Matching Plan Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to matching contributions made for such Participant pursuant to the provisions of the Matching Plan as in effect on December 31, 2001.

(u) "Matching Plan" means the Pioneer Natural Resources USA, Inc. Matching Plan, as in effect from time to time prior to January 1, 2002.

(v) "Mesa After-Tax Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to his or her accrued benefit derived from after-tax contributions to the Mesa Profit-Sharing Plan as in effect on September 30, 1997.

(w) "Mesa Premium Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to Employer contributions made for such Participant pursuant to the provisions of the Mesa Premium Plan as in effect on September 30, 1997.

(x) "Mesa Premium Plan" means the Mesa Employees Premium Plan and Trust Agreement as in effect from time to time prior to October 1, 1997.

(y) "Mesa Profit-Sharing Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to his or her accrued benefit derived from employer contributions to the Mesa Profit-Sharing Plan as in effect on September 30, 1997.

(z) "Mesa Profit-Sharing Plan" means the Mesa Profit-Sharing Plan and Trust Agreement as in effect from time to time prior to October 1, 1997.

(aa) "Non-Highly Compensated Employee" means for a Plan Year any Employee who is not a Highly Compensated Employee for such Plan Year.

(bb) The "Normal Retirement Date" of a Participant means the day such Participant attains the age of 65 years.

(cc) "One Year Break in Service" means a 12-consecutive-month Period of Severance during which an Employee fails to complete a single Hour of Service.

(dd) "Participant" means any individual who was a participant in either the Superseded Plan or the Matching Plan or who has elected to participate in this Plan pursuant to Section 2.2, and whose Vested Interest under this Plan has not been fully distributed.

(ee) "Period of Service" means, for purposes of determining a Participant's Vested Interest in his or her Employer Account, the sum, rounded downward to the nearest whole year, of each period of time commencing with an Employee's Employment Date or Reemployment Date and ending on the first date thereafter a Period of Severance begins (except as provided in subsection (ff) of this Section in the case of an Employee's maternity or paternity leave of absence). Included in such sum to be credited to an Employee shall be each period of time during which the Employee is on an authorized leave of absence for reasons of vacation, sickness, layoff or another occasion designated and applied by an Employer or Affiliated Company on a nondiscriminatory basis, but in no event exceeding one year in length. A Period of Service also includes any Period of Severance of less than 12 consecutive months. If an Employee who has no vested right to any amount credited to his or her Employer Account or Matching Plan Account incurs a One Year Break in Service, such Employee shall forfeit his or her prior Period of Service unless he or she completes an additional one-year Period of Service before the number of his or her consecutive One Year Breaks in Service equals five. Solely for the purpose of determining the Period of Service completed by a Covered Employee who was in the employ of Colorado Interstate Gas Company on May 1, 2001, periods of employment by Colorado Interstate Gas Company or a subsidiary thereof prior to May 1, 2001, shall be considered to be periods of employment by an Employer.

Any provision of this Plan to the contrary notwithstanding, if a Participant participated in the Superseded Plan prior to October 1, 1997, the Period of Service completed by such Participant prior to January 1, 1998, shall be (i) such Participant's years of Vesting Service determined under the Retirement Savings Plan for Employees of Parker & Parsley as of June 27, 1996, (ii) plus one year for the Plan Year ending December 31, 1996, if during such Plan Year such Participant completed a Year of Service under the Retirement Savings Plan for Employees of Parker & Parsley as in effect at the end of such year, (iii) plus one year for the Plan Year ending December 31, 1997, if such Participant either (A) completed a year of Vesting Service as of September 30, 1997, under the Superseded Plan as in effect on such date or (B) completed a one-year Period of Service under the foregoing provisions of this definition during the entire such Plan Year. For purposes of clause (ii) of the preceding sentence, a Participant shall be credited with a number of Hours of Service applying the monthly equivalency method set forth in Labor Reg. ss. 2530.200b-3(e)(1)(iv) to any fractional part of a year credited to such Participant as of June 28, 1996.

(ff) "Period of Severance" means a period of time commencing with the date an Employee ceases to be employed by an Employer or Affiliated Company for reasons of Retirement, Permanent Disability, death, being discharged, or voluntarily ceasing employment, or with the first anniversary of the date of his or her absence for any other reason, and ending with the date such Employee resumes employment with an Employer or Affiliated Company; provided, however, that solely for

purposes of determining whether an Employee incurs a One Year Break in Service, the Period of Severance of an Employee who is absent from work due to the pregnancy of the Employee, the birth of a child of the Employee, the placement of a child with the Employee in connection with the adoption of such child by such Employee, or caring for such child for a period beginning immediately following such birth or placement shall not commence until the second anniversary of the first date of such absence and the period between the first and second anniversaries of the first date of such absence shall be considered neither a Period of Service nor a Period of Severance.

(gg) "Permanent Disability" means the total and permanent incapacity of a Participant to perform the usual duties of his or her employment with an Employer or Affiliated Company as determined by the Committee. Such incapacity shall be deemed to exist when certified by a physician acceptable to the Committee.

(hh) "Pioneer Stock" means the common stock of Pioneer Natural Resources Company, a Delaware corporation, and any successor thereto.

(ii) "Plan" means this Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (Amended and Restated Effective as of January 1, 2002), as in effect from time to time.

(jj) "Plan Year" means the calendar year.

(kk) "Pre-Tax Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to (i) Pre-Tax Contributions and Pre-Tax Bonus Contributions made by an Employer on behalf of such Participant and (ii) any amounts credited to his or her Employee Pre-Tax Contribution Account under the Superseded Plan as in effect on September 30, 1997.

(ll) "Pre-Tax Bonus Contribution" means a contribution made by an Employer to this Plan on behalf of a Participant pursuant to Section 3.1(b).

(mm) "Pre-Tax Contribution" means a contribution made by an Employer to this Plan on behalf of a Participant pursuant to Section 3.1(a).

(nn) "Prior Plan Employer Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to any amounts credited to his or her BOUSA Employer Matching Contribution Account under the Retirement Savings Plan for Employees of Parker & Parsley as in effect on June 27, 1996.

(oo) "Prior Plan Pre-Tax Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to any amounts

credited to his or her Plan A Salary Deferral Contribution Account or his or her BOUSA Plan Salary Deferral Contribution Account under the Retirement Savings Plan for Employees of Parker & Parsley as in effect on June 27, 1996.

(pp) "Qualified Joint and Survivor Annuity" means an annuity which is payable for the life of the Participant with a survivor annuity payable for the life of his or her spouse equal to 50% of the amount of the annuity payable during the life of the Participant; provided, however, that in the case of a Participant who is not married, a Qualified Joint and Survivor Annuity means an annuity which is payable for the life of the Participant. "Alternate Qualified Joint and Survivor Annuity" means an annuity which is payable for the life of the Participant with a survivor annuity payable for the life of his or her spouse equal to 75% or 100% of the amount of the annuity payable during the life of the Participant.

(qq) "Qualified Preretirement Survivor Annuity" means an annuity which is payable for the life of the Participant's surviving spouse.

(rr) "Reemployment Date" means the date an Employee first performs an Hour of Service following a Period of Severance.

(ss) "Retirement" means the termination of a Participant's employment with an Employer or Affiliated Company on or after his or her Normal Retirement Date for any reason other than death or transfer to the employment of another Employer or Affiliated Company.

(tt) "Rollover Account" means the account established and maintained under this Plan by the Committee to record a Participant's interest under this Plan attributable to (i) Rollover Property contributed by such Participant to this Plan pursuant to Section 3.9, (ii) any amounts credited to his or her Rollover Contribution Account under the Superseded Plan as in effect on September 30, 1997, and (iii) any amounts credited to his or her Rollover Account under the Mesa Profit-Sharing Plan as in effect on September 30, 1997.

(uu) "Rollover Property" means property the value of which would be excluded from the gross income of the transferor under Section 402(c), 403(a)(4) or 408(d)(3) of the Code if transferred to the Plan.

(vv) "Superseded Plan" means the Pioneer Natural Resources USA, Inc. 401(k) Plan, as in effect from time to time prior to January 1, 2002. Prior to August 7, 1997, the Superseded Plan was known as the Retirement Savings Plan for Employees of Parker & Parsley.

(ww) "Total Pre-Tax Contributions" means the sum of the Pre-Tax Contributions and Pre-Tax Bonus Contributions made on behalf of a Participant.

(xx) "Trust" means the trust fund established pursuant to Section 4.1.

(yy) "Trustee" means the individual or corporate trustee or trustees from time to time appointed and acting as trustee or trustees of the Trust established pursuant to the Plan.

(zz) "Valuation Date" means each business day.

(aaa) The "Vested Interest" of a Participant means the then vested portion of the amount credited to the Accounts of such Participant at the particular point in time in question.

Section 1.2 Construction. The titles to the Articles and the headings of the Sections in this Plan are placed herein for convenience of reference only and in case of any conflict the text of this instrument, rather than such titles or headings, shall control. Whenever a noun or pronoun is used in this Plan in plural form and there be only one person or entity within the scope of the word so used, or in singular form and there be more than one person or entity within the scope of the word so used, such noun or pronoun shall have a plural or singular meaning as appropriate under the circumstance.

ARTICLE II.

ELIGIBILITY AND PARTICIPATION

Section 2.1 Eligibility. Each participant in either the Superseded Plan or the Matching Plan on December 31, 2001, shall continue as a Participant in this Plan as of January 1, 2002. Each other Covered Employee shall be eligible to become a participant in this Plan on the first day of the first pay period in the calendar month next following his or her Employment Date. If a Participant ceases to be a Covered Employee, such Participant shall remain a Participant under this Plan but no contributions shall be made to the Plan on his or her behalf while he or she is not a Covered Employee.

Section 2.2 Participation. Each Covered Employee who is eligible to participate in the Plan may elect, on a form prescribed by the Committee, to participate in this Plan on the first day of the first pay period in the calendar month following the filing of such election. Any Participant who ceases to be a Covered Employee shall thereupon cease to be eligible to participate in the Plan; provided, however, that if any such Participant is thereafter reemployed as a Covered Employee, he or she shall be eligible to elect to resume participating in the Plan as of the date of such reemployment.

ARTICLE III.

CONTRIBUTIONS, LIMITATIONS AND FORFEITURES

Section 3.1 Pre-Tax and Pre-Tax Bonus Contributions.

(a) Each Participant may elect to have his or her Employer make a Pre-Tax Contribution to the Plan on his or her behalf for each pay period in an amount equal to at least 2% and not in excess of 30%, of his or her Basic Compensation for that pay period. All such contributions shall be made by uniform payroll deductions pursuant to a compensation reduction agreement which authorizes the Employer to pay such contributions to the Trustee on behalf of the Participant.

(b) In addition, each Participant may elect to have his or her Employer make a Pre-Tax Bonus Contribution to the Plan on his or her behalf in an amount equal to at least 2% and not in excess of 30%, of the bonus payable to such Participant under the Employer's annual bonus program.

(c) The Committee shall establish and maintain for each Participant a Pre-Tax Account. All amounts attributable to Pre-Tax Contributions and Pre-Tax Bonus Contributions made by an Employer on behalf of such Participant pursuant to this Section 3.1 shall be credited to such Participant's Pre-Tax Account.

(d) A Participant may change the applicable percentage of such payroll (or bonus) deductions as of the first day of the first pay period of any calendar month, or at any time suspend his or her election to have Pre-Tax Contributions and/or Pre-Tax Bonus Contributions made to the Plan, provided that written notice of such change or suspension is delivered to the Committee within such reasonable period of time prior to the effective date thereof as the Committee may require.

(e) Any provision of this Plan to the contrary notwithstanding, the amount of Total Pre-Tax Contributions made to the Plan by an Employer on behalf of a Participant for a calendar year when added to the amount of any other elective deferrals within the meaning of Section 402(g)(3) of the Code made with respect to such Participant pursuant to any other plan, contract or arrangement of an Employer or Affiliated Company for such calendar year shall not exceed the dollar limitation contained in Section 402(g) of the Code in effect for such calendar year, except to the extent permitted under Section 3.3 of the Plan and Section 414(v) of the Code, if applicable. If the percentage of Total Pre-Tax Contributions elected by a Participant results in such contributions equaling the limitation imposed by Section 402(g) of the Code prior to the end of a calendar year, then such election by the Participant shall be deemed to be an election to make After-Tax Contributions to the Plan at the time such dollar limitation is exceeded unless otherwise elected by the Participant; provided, however, that to the extent permitted by Section 414(v) of the Code and the regulations thereunder, such election shall first be deemed to be

an election to make Catch-Up Contributions to the Plan. In the event such contributions are not timely recharacterized and the limitation of this subsection (e) is exceeded with respect to a Participant for a Plan Year, then if such Participant notifies the Committee of the amount of Total Pre-Tax Contributions that exceeded such limitation within such reasonable period of time prior to the first April 15 following such year as the Committee may prescribe in its absolute discretion, the excess Total Pre-Tax Contributions (along with any income allocable thereto for such year, but not for the gap period following such year) shall be distributed to such Participant no later than such April 15. A Participant will be deemed to have so notified the Committee of excess elective deferrals for a calendar year if, and only to the extent, such excess arises on account of Total Pre-Tax Contributions made to this Plan and elective deferrals made to other plans maintained by an Employer or Affiliated Company for such calendar year. Any such excess deferrals distributed to a Participant shall be distributed first from any Pre-Tax Bonus Contributions and then, to the extent necessary, from Pre-Tax Contributions. The income allocable to any excess Total Pre-Tax Contributions for a Participant for a taxable year shall be determined by multiplying the amount of income allocable to such Participant's Pre-Tax Account for such year by a fraction, the numerator of which is the amount of excess Total Pre-Tax Contributions for such year and the denominator of which is the sum of the amount credited to such Participant's Pre-Tax Account as of the beginning of such year plus the amount of such Participant's Total Pre-Tax Contributions for such year. If any portion of a Pre-Tax Contribution is distributed or recharacterized pursuant to this subsection, any portion of a Matching Contribution (along with any income allocable thereto) made to this Plan for such Participant that matches the distributed or recharacterized Pre-Tax Contribution shall be forfeited.

(f) An Employer may amend or revoke any Participant's compensation reduction agreement at any time during a Plan Year if such amendment or revocation is deemed by such Employer to be necessary or appropriate to ensure that all applicable limitations, including those set forth in Sections 3.1(e), 3.7 and 10.3 are met for such year.

Section 3.2 Matching Contributions. For each pay period an Employer shall make to the Plan for each Participant in its employ and allocate to such Participant's Employer Account a Matching Contribution equal to 200 percent of the Pre-Tax Contributions made by the Employer on such Participant's behalf during such pay period which are not in excess of five percent of such Participant's Basic Compensation for such pay period. The Committee shall establish and maintain an Employer Account for each Participant. All Matching Contributions made for a Participant pursuant to this Section shall be credited to such Participant's Employer Account.

Section 3.3 Catch-Up Contributions. All Employees who are eligible to make Pre-Tax Contributions to this Plan and who have attained age 50 before the close of the Plan Year shall be eligible to make Catch-Up Contributions pursuant to a compensation reduction agreement and in accordance with, and subject to the limitations of, Section 414(v) of the Code and the regulations thereunder. Such Catch-Up Contributions shall not be taken into account for purposes of the provisions of the Plan implementing the required limitations of Sections 402(g) and 415 of the Code. The Plan shall not be treated as failing to satisfy the

provisions of the Plan implementing the requirements of Section 401(k)(3), 401(k)(11), 401(k)(12), 410(b), or 416 of the Code, as applicable, by reason of the making of such Catch-Up Contributions.

Section 3.4 After-Tax Contributions.

(a) Each Participant may elect to make an After-Tax Contribution to the Plan for each pay period in an amount which, when combined with any Pre-Tax Contributions made to the Plan on behalf of such Participant for that pay period, shall not exceed 50% of the Compensation of such Participant during such pay period.

(b) The Committee shall establish and maintain for each Participant an After-Tax Account. All amounts attributable to After-Tax Contributions made by a Participant pursuant to this Section 3.4 shall be credited to such Participant's After-Tax Account.

(c) After-Tax Contributions may be made in whole or in part by uniform payroll deductions which the Participant shall in writing authorize his or her Employer to withhold and pay over to the Trustee. A Participant may change the applicable percentage of such payroll deductions as of the first day of the first pay period of any calendar month, or at any time suspend his or her election to have After-Tax Contributions made to the Plan, provided that written notice of such change or suspension is delivered to the Committee within such reasonable period of time prior to the effective date thereof as the Committee may require.

(d) At any time and from time to time during a Plan Year, the Company may limit the After-Tax Contributions made by a Participant or suspend the making of After-Tax Contributions if the Company, in its absolute discretion, deems such to be necessary or appropriate to ensure that all applicable limitations, including those set forth in Sections 3.7 and 10.3, are satisfied for such year.

Section 3.5 Payment of Contributions. Pre-Tax Contributions, Catch-Up Contributions and After-Tax Contributions made to the Plan by an Employer for or on behalf of Participants for a pay period shall be paid to the Trustee in cash as soon as practicable after such pay period ends, but no later than the 15th business day after the end of the month in which such pay period ends. Pre-Tax Bonus Contributions made to the Plan on behalf of Participants shall be paid to the Trustee in cash as soon as practicable after the bonus payment is made, but no later than the 15th day of the month after the end of the month in which such bonus payment is made. Matching Contributions made to the Plan for a pay period shall be paid to the Trustee as soon as practicable, but no later than 30 days after the end of the month in which such pay period ends.

Section 3.6 Return of Employer Contributions. Contributions made to this Plan are conditioned upon being currently deductible under Section 404 of the Code. Any provision of this Plan to the contrary notwithstanding, upon an Employer's request, any such contribution or portion thereof made to this Plan by such Employer which (i) was made under a mistake of fact which is

subsequently discovered, or (ii) is disallowed as a deduction under Section 404 of the Code, shall be returned to such Employer to the extent not previously distributed to Participants or their beneficiaries; provided, however, that the amounts returnable to an Employer pursuant to this Section shall be reduced by any Trust losses allocable thereto and shall be returned to such Employer only if such return is made within one year after the mistaken payment of the contribution or the date of the disallowance of the deduction, as the case may be. Except as provided in this Section, no contribution made by an Employer pursuant to this Plan shall ever revert to or be recoverable by any Employer.

Section 3.7 Nondiscrimination Testing.

(a) Any provision of this Plan to the contrary notwithstanding, if for any Plan Year the actual deferral percentage for the group of Highly Compensated Employees eligible to elect to have Pre-Tax Contributions or Pre-Tax Bonus Contributions made during such Plan Year fails to satisfy one of the following tests:

(1) the actual deferral percentage for said group of Highly Compensated Employees is not more than 1.25 times the actual deferral percentage for the preceding Plan Year for all Non-Highly Compensated Employees eligible during the preceding Plan Year to elect to have Pre-Tax Contributions or Pre-Tax Bonus Contributions made on their behalf, or

(2) the excess of the actual deferral percentage for said group of Highly Compensated Employees over the actual deferral percentage for the preceding Plan Year for all Non-Highly Compensated Employees eligible during the preceding Plan Year to elect to have Pre-Tax Contributions or Pre-Tax

Bonus Contributions made on their behalf is not more than two percentage points, and the actual deferral percentage for said group of Highly Compensated Employees is not more than two times the actual deferral percentage for the preceding year for all Non-Highly Compensated Employees eligible during the preceding Plan Year to elect to have Pre-Tax Contributions or Pre-Tax Bonus Contributions made on their behalf,

then the actual deferral percentage of Participants who are members of said group of Highly Compensated Employees shall be reduced by reducing the actual deferral percentages of the Highly Compensated Employees with the largest individual actual deferral percentages to the largest uniform actual deferral percentage (commencing with the Highly Compensated Employee with the largest actual deferral percentage and reducing his or her actual deferral percentage to the extent necessary to satisfy one of the above tests or to lower such actual deferral percentage to the actual deferral percentage of the Highly Compensated Employee with the next largest actual deferral percentage, and repeating this process as necessary) that permits the actual deferral percentage for said group of Highly Compensated Employees to satisfy one of said tests. For purposes of this subsection (a), the term "actual deferral percentage" for a specified group of Employees for a

Plan Year means the average of the ratios (calculated separately for each Employee in such group and after any distributions to Highly Compensated Employees required to satisfy the limitation imposed by Section 402(g) of the Code) of (i) the aggregate amount of Total Pre-Tax Contributions made on behalf of each such Employee for that year, to (ii) the amount of such Employee's Compensation for that year or, in the Committee's discretion, only for such portion of that year during which the Employee was eligible to participate in the Plan. If two or more plans that include cash or deferred arrangements are considered as one plan for purposes of Section 401(a)(4) or 410(b) of the Code (other than for purposes of the average benefit percentage test), the cash or deferred arrangements included in such plans shall be treated as one arrangement for purposes of this subsection (a). If a Highly Compensated Employee is a participant in two or more cash or deferred arrangements of an Employer, then for purposes of determining the actual deferral ratio of such Employee, all such cash or deferred arrangements (other than those that may not be permissively aggregated) shall be treated as one cash or deferred arrangement.

(b) The aggregate amount of any Total Pre-Tax Contributions which may not be credited to Pre-Tax Accounts for a Plan Year because of the limitation contained in subsection (a) of this Section, calculated by adding together the dollar amount of excess contributions determined in subsection (a) of this Section for each affected Highly Compensated Employee, shall be distributed to Highly Compensated Employees (along with any income allocable to such excess contributions for such Plan Year, but not for the gap period following such Plan Year) no later than the last day of the Plan Year immediately following such year (and, if practicable, within 2 1/2 months after the end of such year). The amount of Total Pre-Tax Contributions to be distributed to a particular Highly Compensated Employee shall be determined on the basis of the amount of Total Pre-Tax Contributions made for each Highly Compensated Employee commencing with the Highly Compensated Employee with the largest amount of Total Pre-Tax Contributions for such Plan Year and reducing his or her Total Pre-Tax Contributions to the extent necessary to lower such amount to the amount of Total Pre-Tax Contributions of the Highly Compensated Employee with the next largest amount of Total Pre-Tax Contributions, and repeating this process as necessary to distribute such aggregate amount; provided, however, that the amount of Total Pre-Tax Contributions to be distributed shall first be reduced by any excess deferrals to be distributed pursuant to Section 402(g) of the Code. Any such excess contribution shall be distributed first from any Pre-Tax Contributions and then, to the extent necessary, from Pre-Tax Bonus Contributions. The income allocable to any such excess contributions for a Participant for a Plan Year shall be determined by multiplying the amount of income allocable to such Participant's Pre-Tax Account for such year by a fraction, the numerator of which is the amount of the excess contributions for such year and the denominator of which is the sum of the amount credited to such Participant's Pre-Tax Account as of the beginning of such year plus the amount of such Participant's Total Pre-Tax Contributions for such year. Any provision of this Plan to the contrary notwithstanding, Total Pre-Tax Contributions otherwise distributable pursuant to this subsection (b) to a Participant who is eligible to make Catch-Up

Contributions to the Plan shall, to the extent permitted by Section 414(v) of the Code and the regulations thereunder, be treated as a Catch-Up Contribution. If any portion of a Pre-Tax Contribution made by an Employer on behalf of a Participant is distributed to such Participant or is treated as a Catch-Up Contribution pursuant to the foregoing provisions of this subsection (b), any portion of a Matching Contribution (along with any income allocable thereto) made for such Participant that matches the distributed Pre-Tax Contribution or recharacterized Catch-Up Contribution shall be forfeited.

(c) Any provision of this Plan to the contrary notwithstanding, if for any Plan Year the contribution percentage for the group of Highly Compensated Employees eligible to receive an allocation of Matching Contributions or to make After-Tax Contributions to the Plan for such Plan Year fails to satisfy one of the following tests:

> (1) the contribution percentage for said group of Highly Compensated Employees is not more than 1.25 times the contribution percentage for the preceding Plan Year for all Non-Highly Compensated Employees eligible for the preceding Plan Year to receive an allocation of Matching Contributions or make After-Tax Contributions, or
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> (2) the excess of the contribution percentage for said group of Highly Compensated Employees over the contribution percentage for the preceding Plan Year for all Non-Highly Compensated Employees eligible for the preceding Plan Year to receive an allocation of Matching Contributions or make After-Tax Contributions is not more than two percentage points, and the contribution percentage for said group of Highly Compensated Employees is not more than two times the contribution percentage for the preceding Plan Year for all Non-Highly Compensated Employees eligible for the preceding Plan Year to receive an allocation of Matching Contributions or make After-Tax Contributions,

then the contribution percentage of Participants who are members of said group of Highly Compensated Employees shall be reduced by reducing the contribution percentages of the Highly Compensated Employees with the largest individual contribution percentages to the largest uniform contribution percentage (commencing with the Highly Compensated Employee with the largest contribution percentage and reducing his or her contribution percentage to the extent necessary to satisfy one of the above tests or to lower such contribution percentage to the contribution percentage of the Highly Compensated Employee with the next largest contribution percentage, and repeating this process as necessary) that permits the contribution percentage for said group of Highly Compensated Employees to satisfy one of said tests. For purposes of this subsection (c), the term "contribution percentage" for a specified group of Employees for a Plan Year means the average of the ratios (calculated separately for each Employee in such group and after application of the reduction provisions of subsection (a) and the forfeiture provisions of subsection (b) of this Section) of (i) the aggregate amount of After-Tax Contributions and Matching Contributions

made by or for such Employee (and, at the election of the Committee, the Total Pre-Tax Contributions made on behalf of such Employee) for that year, to (ii) the amount of such Employee's Compensation for that year or, in the Committee's discretion, only for such portion of that year during which the Employee was eligible to participate in the Plan. If two or more plans to which matching contributions or employee after-tax contributions are made are considered as one plan for purposes of Section 410(b) of the Code (other than for purposes of the average benefit percentage test), such plans shall be treated as one plan for purposes of determining the contribution percentages for this subsection (c). If a Highly Compensated Employee is a participant in two or more plans to which matching contributions or employee after-tax contributions are made, then for purposes of determining the contribution ratio of such Employee, all such plans (other than those that may not be permissively aggregated) shall be treated as one plan.

(d) The aggregate amount of any Matching Contributions and After-Tax Contributions which may not be credited to Participant's Accounts for a Plan Year because of the limitation contained in subsection (c) of this Section, calculated by adding together the dollar amount of excess aggregate contributions determined in subsection (c) of this Section for each affected Highly Compensated Employee, shall be forfeited if forfeitable, but if not forfeitable, distributed to such Highly Compensated Employees (along with any income allocable to such excess aggregate contributions for such Plan Year, but not for the gap period following such Plan Year) no later than the last day of the Plan Year immediately following such year (and, if practicable, within 2 1/2 months after the end of such year). The amount to be distributed to a particular Highly Compensated Employee shall be determined on the basis of the amount of Matching Contributions and After-Tax Contributions made by or for each such Highly Compensated Employee commencing with the Highly Compensated Employee with the largest amount of Matching Contributions and After-Tax Contributions for such Plan Year and reducing first his or her After-Tax Contributions and then, if necessary, Matching Contributions to the extent necessary to lower such total amount to the amount of Matching Contributions and After-Tax Contributions of the Highly Compensated Employee with the next largest amount of Matching Contributions and After-Tax Contributions, and repeating this process as necessary to distribute such aggregate amount. The income allocable to any such excess aggregate contributions for a Participant for a Plan Year shall be determined by multiplying the amount of income allocable to such Participant's Employer Account or After-Tax Account, whichever is applicable, for such year by a fraction, the numerator of which is the amount of the excess aggregate contributions for such year and the denominator of which is the sum of the amount credited to such Participant's Employer Account or After-Tax Account, whichever is applicable, as of the beginning of such year plus the amount of Matching Contributions or After-Tax Contributions, as applicable, made for such Participant for such year.

(e) Any provision of this Section to the contrary notwithstanding, the Company in its discretion may cause the provisions of subsections (a) and (c) of this Section to be satisifed without use of the corrective provisions set forth in subsections (b) and (d) of this Section by requiring each Employer to make a qualified non-elective contribution and/or a qualified matching contribution to the Plan to be allocated to the Pre-Tax Accounts (with respect to a contribution intended to be taken into account for purposes of determining the actual deferral percentage pursuant to subsection (a)) or the Employer Accounts (with respect to a contribution intended to be taken into account for purposes of determining the contribution percentage pursuant to subsection (c)) of those Participants who were Non-Highly Compensated Employees in the employ of (or on authorized leave of absence from) an Employer on the last day of such Plan Year. A qualified non-elective contribution shall be allocated to the eligible Participants in the proportion that the Basic Compensation of each such eligible Participant while both a Participant and a Covered Employee during that year bears to the Basic Compensation of all such eligible Participants while both Participants and Covered Employees during that year. A qualified matching contribution shall be allocated to the eligible Participants in the proportion that the Pre-Tax Contributions made with respect to each such eligible Participant for such Plan Year bears to the Pre-Tax Contributions made with respect to all such eligible Participants for such Plan Year.

(f) Any provision of this Plan to the contrary notwithstanding, the determination of the actual deferral percentage and the contribution percentage required by this Section for Non-Highly Compensated Employees for the preceding Plan Year shall be made in accordance with Sections 401(k) and 401(m) of the Code and any regulations or other authorities issued thereunder.

Section 3.8 Application of Forfeitures. As soon as practicable after the valuation of all Accounts at the end of each Plan Year, all amounts forfeited during that Plan Year shall first be applied to restore any forfeited Accounts required to be restored pursuant to Sections 6.5 and 6.8, and any forfeitures in excess of the amount needed to restore any such Account may be applied to pay administrative expenses in accordance with Section 7.4. Any remaining forfeitures for such Plan Year, if any, shall be used to reduce the amount of the earliest subsequent Matching Contributions an Employer otherwise would be required to make to the Plan.

Section 3.9 Rollover Contributions. With the consent of and subject to such reasonable conditions and limitations as may be imposed by the Committee, any Covered Employee (regardless of whether he or she is a Participant) may contribute Rollover Property in cash to the Plan. Each contribution of Rollover Property shall be credited to the Covered Employee's Rollover Account. An Employee who is not a Participant, but for whom a Rollover Account is being maintained, shall be accorded all of the rights and privileges of a Participant under the Plan except that no contributions (other than contributions of Rollover Property) shall be made for or on behalf of such Employee until he or she meets the eligibility and participation requirements of Article II. Subject to the Committee's consent, the Plan will accept (i) a direct rollover of an eligible rollover distribution from: (A) a qualified plan described in Section 401(a) or 403(a) of the Code, including after-tax employee contributions, (B) an annuity contract described in Section 403(b) of the Code, excluding after-tax employee contributions, or (C) an eligible plan under Section 457(b) of the Code

which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state; or (ii) a Participant contribution of an eligible rollover distribution from: (A) a qualified plan described in Section 401(a) or 403(a) of the Code, (B) an annuity contract described in Section 403(b) of the Code, or (C) an eligible plan under Section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state. The Plan will accept a Participant rollover contribution of the portion of a distribution from an individual retirement account or annuity described in Section 408(a) or 408(b) of the Code that is eligible to be rolled over and would otherwise be includible in gross income of the Participant.

ARTICLE IV.

TRUST FUND AND VALUATIONS

Section 4.1 Trust and Trustee. All of the contributions paid to the Trustee pursuant to this Plan and the Superseded Plan, together with the income therefrom and the increments thereof, shall be held in trust by the Trustee under the terms and provisions of the separate trust agreement between the Trustee and the Company, a copy of which is attached hereto and incorporated herein by this reference for all purposes, establishing a trust fund known as the PIONEER NATURAL RESOURCES USA, INC. 401(k) AND MATCHING TRUST for the exclusive benefit of the Participants and their beneficiaries.

Section 4.2 Trust Investment Options. All amounts credited to a Participant's Accounts may be invested in Pioneer Stock and/or one or more of the Investment Funds at the direction of such Participant in accordance with the provisions of this Section. The assets of the Trust (other than Pioneer Stock) shall be divided into such number and kind of separate and distinct Investment Funds as the Committee in its absolute discretion shall authorize from time to time. The assets of the Trust allocated to a particular Investment Fund shall be invested by the Trustee and/or one or more investment managers duly appointed in accordance with the provisions of the trust agreement establishing the Trust, as the case may be, in such type of property acceptable to the Trustee as the Trustee is directed to acquire and hold for such Investment Fund. Upon becoming a Participant in the Plan, each Participant shall direct, in the manner prescribed by the Committee in its absolute discretion, that all amounts credited to his or her Accounts under the Plan shall be invested, in percentage multiples authorized by the Committee, in one or more of the Investment Funds. Subject to such conditions and limitations as the Committee in its absolute discretion may prescribe from time to time for application to all Participants on a uniform basis, a Participant may change his or her investment direction with respect to future contributions or redirect the investment of the amounts credited to his or her Accounts provided that notice of such change is delivered to or in the manner directed by the Committee within such reasonable period of time prior to the effective date thereof as the Committee may require.

Section 4.3 Valuation and Adjustment of Accounts. As of each Valuation Date, the Trustee shall determine the fair market value of all assets of the Trust with the value of the assets of each Investment Fund being separately determined. On the basis of such valuations and in accordance with such procedures as may be specified from time to time by the Committee, the portion of each Account invested in a particular Investment Fund shall be adjusted by the Committee to reflect its proportionate share of the income collected and accrued, realized and unrealized profits and losses, expenses and all other transactions attributable to that particular Investment Fund for the valuation period then ended. All cash dividends, stock dividends, stock splits and other amounts received by the Trustee with respect to Pioneer Stock held for an Account (including the forfeiture account established pursuant to Section 6.5) shall be credited to such Account. The amount of any distribution, withdrawal or forfeiture shall be determined on the basis of the most recent valuation preceding the date of distribution, withdrawal or forfeiture, as the case may be.

ARTICLE V.

VESTING

Section 5.1 Fully Vested Accounts. The amounts credited to a Participant's After-Tax Account, Mesa After-Tax Account, Mesa Premium Account, Mesa Profit-Sharing Account, Pre-Tax Account, Prior Plan Employer Account, Prior Plan Pre-Tax Account, and Rollover Account shall be fully vested at all times.

Section 5.2 Vesting of Employer Account.

(a) The amounts credited to the Employer Account and Matching Plan Account of a Participant shall become fully vested upon the occurrence of any of the following events while the Participant is in the employ of (or on authorized leave of absence from) an Employer or Affiliated Company: (i) the completion of an Hour of Service by the Participant on or after the date he or she attains age 60, (ii) the Participant's death, or (iii) the Participant's Permanent Disability. Unless sooner vested pursuant to the preceding sentence, and except as provided in subsection (b) of this Section and Section 5.3, the amounts credited to a Participant's Employer Account and Matching Plan Account shall vest in accordance with the following schedule:

Period of Service Completed by Participant	Percentage Vested
Less than 1 year	None
1 year	25%
2 years	50%
3 years	75%
4 or more years	100%

(b) If a Participant makes an in-service withdrawal under Section 6.6 from his or her Employer Account at a time when the Participant is not fully vested, the Participant's vested amount in such account on any date thereafter shall be an amount X determined by the following formula: $X = P(AB + D) - D$. For purposes of this formula, P is the Participant's vested percentage under the Plan's vesting schedule on the relevant date, AB is the account balance on the relevant date and D is the amount of the Participant's in-service withdrawal.

Section 5.3 Special Vesting Provisions.

(a) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Employer Account and/or Matching Plan Account of a Participant who is specifically designated by the Vice President Administration of the Company as being involuntarily terminated in connection with the divestiture program and corporate restructuring announced on February 10, 1998, shall become fully vested and nonforfeitable on the date of such involuntary termination.

(b) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Employer Account and/or Matching Plan Account of a Participant who is specifically designated by the Vice President Administration of the Company as being involuntarily terminated in connection with the corporate restructuring announced on November 11, 1998, shall become fully vested and nonforfeitable on the date of such involuntary termination.

(c) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Matching Plan Account of a Participant who is specifically designated by the Vice President Administration of the Company as being involuntarily terminated in connection with the sale by the Company of the Plum Creek Plant, Leon County, Texas, to a third party shall become fully vested and nonforfeitable on the date of such involuntary termination.

(d) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Matching Plan Account of a Participant who is specifically designated by the Vice President - Administration and Risk Management of the Company as being involuntarily terminated in connection with one of the following events shall become fully vested and nonforfeitable on the date of such involuntary termination:

(i) the transfer of operations of the Howard Parker/Joe Parsley Joint Venture wells to a third party;

(ii) the sale of Iatan Field properties to a third party;

(iii) the reorganization of Offshore Operations effective September 22, 1999;

(iv) the restructuring and consolidation of the Domestic Reservoir Engineering Department effective February 15, 2000; or

(v) the sale of NationsBank building, Midland, Texas.

(e) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Matching Plan Account of a Participant who is specifically designated by the Vice President - Administration and Risk Management of the Company as being involuntarily terminated in connection with the implementation of the TOW Production System technology, shall become fully vested and nonforfeitable on the date of such involuntary termination.

ARTICLE VI.

VALUATIONS, DISTRIBUTIONS AND WITHDRAWALS

Section 6.1 Time of Distribution.

(a) Distribution to a Participant or beneficiary under this Article shall be made or commence being made no later than 60 days after the close of the Plan Year in which the latest of the following occurs: (i) the Participant's Normal Retirement Date, (ii) the tenth anniversary of the year in which the Participant commenced participation in the Plan, or (iii) the Participant's separation from the employment of an Employer for any reason other than his or her transfer to the employment of another Employer or Affiliated Company.

(b) Any provision of this Plan to the contrary notwithstanding, in the case of a Participant who is a five-percent owner (as defined in Section 416(i) of the Code), distribution to such Participant under the Plan shall be made or commence being made no later than April 1 of the calendar year following the calendar year in which the Participant attains age 70 1/2. Distributions that commence being made pursuant to the preceding sentence to a Participant who has not separated from the employment of an Employer or Affiliated Company shall be made pursuant to Section 6.2 as if the Participant had terminated employment at such time and shall be made in accordance with the minimum distribution requirements of Section 401(a)(9) of the Code and such regulations thereunder as may be applicable from time to time (or for periods prior to the effective date of final regulations under Section 401(a)(9) of the Code, pursuant to the regulations that were proposed on January 17, 2001); provided, however, that if the Participant elects to waive the normal form of payment in accordance with Section 6.2, the alternative form of distribution shall be the minimum amounts required to be distributed pursuant to Section 401(a)(9) of the Code and such regulations thereunder as may be applicable from time to time (or for periods prior to the effective date of final regulations under Section 401(a)(9) of the Code pursuant to regulations that were proposed on January 17, 2001), with any amount remaining upon the termination of the Participant's employment or the death of the Participant to be paid in accordance with Section 6.2 or Section 6.3, whichever is applicable. Further, any other Participant who attained age 70 1/2 prior to January 1, 1999, and who elected to continue to receive distributions prior to such Participant's termination of employment shall be entitled receive an annual distribution in accordance with the preceding sentence (or may elect a larger or smaller amount for such annual distribution) unless and until such Participant revokes such election. Any provision of this Plan to the contrary notwithstanding, no distribution shall be made from this Plan that would violate Section 401(k) of the Code.

(c) Subject to the provisions of this Article requiring that distributions and withdrawals be made in the form of an annuity contract, distributions and withdrawals shall be made in cash, except that amounts credited to an Account that are invested in Pioneer Stock may, at the election of the Participant, be distributed in the form of Pioneer Stock with cash in lieu of fractional shares.

(d) Any provision of this Plan to the contrary notwithstanding, (i) all distributions from the Plan shall be made in accordance with Section 401(a)(9) of the Code and the regulations thereunder, and (ii) all optional forms of benefit under the Plan, the Superseded Plan, the Matching Plan, the Mesa Premium Plan, and the Mesa Profit-Sharing Plan that are protected benefits under Section 411(d)(6) of the Code shall continue to be optional forms of benefit for Participants to whom such optional forms of benefit apply notwithstanding any subsequent amendment purporting to revise or delete any such optional form of benefit, except to the extent that such optional forms of benefit may be deleted in accordance with applicable law.

Section 6.2 Distribution of Retirement and Disability Benefits.

(a) Except as otherwise provided in this Section, upon the Retirement or termination of employment on account of Permanent Disability of a Participant, the Vested Interest of such Participant shall be distributed to such Participant by the Trustee at the direction of the Committee in a single distribution; provided, however, that if such Participant's Vested Interest exceeds $5,000, he or she may elect to receive his or her Vested Interest in monthly, quarterly or annual installment distributions over a period of two or more years with the first such installment to be payable within 90 days after the end of the Plan Year in which the Participant's employment terminates. Such installment payments may be made over a period of years not to exceed one or a combination of the following periods: (i) the life of the Participant, (ii) the lives of the Participant and his or her designated beneficiary, (iii) a period certain not extending beyond the life expectancy of the Participant, and (iv) a period certain not extending beyond the joint life and last survivor expectancy of the Participant and his or her designated beneficiary. Any provision of

Section 6.3 to the contrary notwithstanding, if a Participant who elected installment payments dies prior to the distribution of the entire amount of his or her Vested Interest, the remaining portion thereof shall be distributed to his or her beneficiary or beneficiaries, as determined in accordance with Section 6.3(a), in a single distribution within 90 days after the end of the Plan Year during which the Participant died. Notwithstanding the foregoing provisions of this Section 6.2, no distribution shall be made upon a Participant's termination of employment on account of Permanent Disability prior to his or her Normal Retirement Date unless (i) such Participant elects to receive such distribution or (ii) such Participant's Vested Interest does not exceed $5,000. For purposes of determining whether the value of a Participant's Vested Interest exceeds or does not exceed $5,000, the value of a Participant's Vested Interest shall be determined without regard to the value of the Participant's Rollover Account.

(b) Except as otherwise provided in this subsection (b), upon the Retirement or termination of employment on account of Permanent Disability of a Participant whose Vested Interest exceeds $5,000, such Participant's Matching Plan Account, Mesa Premium Account, Prior Plan Employer Account and Prior Plan Pre-Tax Account shall be distributed to him or her by the Trustee at the direction of the Committee in the form of a Qualified Joint and Survivor Annuity contract to be purchased from a company selected by the Committee and commencing in payment as soon as practicable. Not more than 90 days prior to the date such annuity contract is to commence in payment, the Committee shall provide such Participant with a written explanation of (i) the terms and conditions of the Qualified Joint and Survivor Annuity, (ii) his or her right to make, and the effect of, an election to waive the Qualified Joint and Survivor Annuity form of benefit, (iii) the rights of his or her spouse with respect to the receipt and waiver of the Qualified Joint and Survivor Annuity, and (iv) the right to make, and the effect of, a revocation of an election to waive the Qualified Joint and Survivor Annuity. The written explanation shall be required at least 30 days prior to the date the Qualified Joint and Survivor Annuity contract is to commence in payment; provided, however, that a Participant may elect (with any applicable spousal consent) to waive such requirement if the distribution to the Participant commences no earlier than 8 days after such explanation is provided. After receiving the written explanation, the Participant may elect at any time during the 90-day period ending on the date the annuity contract is to commence in payment to waive the Qualified Joint and Survivor Annuity form of benefit and also may revoke any such election during such period. Any such election to waive a Qualified Joint and Survivor Annuity form of benefit by a married Participant will be effective only if the spouse of such Participant consents in writing within the 90-day period preceding such date to both the election and the optional form of benefit selected by the Participant and such consent is witnessed by a notary public. Any amount payable from the Matching Plan Account, Mesa Premium Account, Prior Plan Employer Account or Prior Plan Pre-Tax Account upon the Retirement or Permanent Disability of a Participant who has elected to waive the Qualified Joint and Survivor Annuity form of benefit as provided above shall be distributed to such Participant by the Trustee at the direction of the Committee in accordance with subsection (a) of this Section; provided, however, that a Participant who has an amount

payable from his or her Matching Plan Account or Mesa Premium Account may, in addition to the optional forms available under subsection (a), elect to have such amounts paid in the form of an Alternate Qualified Joint and Survivor Annuity. For purposes of determining whether the value of a Participant's Vested Interest exceeds $5,000, the value of a Participant's Vested Interest shall be determined without regard to the value of the Participant's Rollover Account.

Section 6.3 Distribution of Death Benefit.

(a) Except as otherwise provided in this Section, upon the death of a Participant, the Vested Interest of such Participant shall be distributed by the Trustee at the direction of the Committee to such Participant's beneficiary or beneficiaries determined in accordance with this subsection (a). Any amount payable under the Plan upon the death of a married Participant shall be distributed to the surviving spouse of such Participant unless such Participant designates otherwise with the written consent of his or her spouse which is witnessed by a notary public. Any amount payable under the Plan upon the death of a Participant who is not married or who is married but has designated, as provided above, a beneficiary other than his or her spouse, shall be distributed to the beneficiary or beneficiaries designated by such Participant. Such designation of beneficiary or beneficiaries shall be made in writing on a form prescribed by the Committee and, when filed with or as directed by the Committee, shall become effective and remain in effect until changed by the Participant by the filing of a new beneficiary designation form with the Committee. If an unmarried Participant fails to so designate a beneficiary, or in the event all of a Participant's designated beneficiaries are individuals who predecease such Participant, then the Committee shall direct the Trustee to distribute the amount payable under the Plan to such Participant's surviving spouse, if any, but if none, to such Participant's estate. All distributions under this subsection (a) shall be made in a single distribution as soon as practicable following a Participant's death; provided, however, that if the Participant's Vested Interest exceeds $5,000, he or she may elect (or if the Participant does not elect, his or her designated beneficiary may elect) that distribution be made in monthly, quarterly or annual installments over a period of two or more years with the first such installment to be payable within 90 days after the end of the Plan Year in which the Participant died. Installment payments may be made only to an individual over a period of years not to exceed one or a combination of the following periods: (i) the life of the Participant's designated beneficiary, or (ii) a period certain not extending beyond the life expectancy of the Participant's designated beneficiary. For purposes of determining whether the value of a Participant's Vested Interest exceeds $5,000, the value of a Participant's Vested Interest shall be determined without regard to the value of the Participant's Rollover Account.

(b) Any provision of subsection (a) of this Section to the contrary notwithstanding, except as otherwise provided in this subsection (b), upon the death of a married Participant whose Vested Interest exceeds $5,000, such Participant's Matching Plan Account, Mesa Premium Account, Prior Plan Employer Account and Prior Plan Pre-Tax

Account shall be distributed to his or her surviving spouse in the form of a Qualified Preretirement Survivor Annuity contract to be purchased from a company selected by the Committee and commencing in payment on the date that would have been such Participant's Normal Retirement Date if he or she were still living. The Committee shall provide each such married Participant with a written explanation of the Qualified Preretirement Survivor Annuity provided above, including the Participant's right to waive the distribution of such Qualified Preretirement Survivor Annuity with the consent of his or her spouse and to revoke any such waiver, within whichever of the following periods ends last: (i) the period beginning with the first day of the Plan Year in which the Participant attains the age of 32 and ending with the close of the Plan Year preceding the Plan Year in which the Participant attains the age of 35, (ii) the one-year period after the individual becomes a Participant, or (iii) the one-year period after separation from employment in the case of a Participant who separates before attaining age 35. Each married Participant may elect at any time prior to such Participant's death to waive the Qualified Preretirement Survivor Annuity form of benefit provided above so that his or her entire benefit may be paid to his or her designated beneficiary. No election to waive the Qualified Preretirement Survivor Annuity will be effective upon the Participant's death unless such election designates a beneficiary that cannot be changed without spousal consent, the Participant's surviving spouse consents in writing to such election and such consent is witnessed by a notary public. A spousal consent will be valid only with respect to the spouse who signs the consent and such consent shall be irrevocable. A married Participant may revoke any such election to waive the Qualified Preretirement Survivor Annuity at any time prior to his or her death. The amount payable under the Plan upon the death of a married Participant who has elected, as provided above, to waive the Qualified Preretirement Survivor Annuity shall be distributed in accordance with subsection (a) of this Section. The surviving spouse of any deceased Participant may elect in writing after the Participant's death to receive the entire benefit otherwise payable to such surviving spouse in accordance with this subsection (a) of this Section. For purposes of determining whether the value of a Participant's Vested Interest exceeds $5,000, the value of a Participant's Vested Interest shall be determined without regard to the value of the Participant's Rollover Account.

Section 6.4 Distribution of Separation from Employment Benefit.

(a) Except as otherwise provided in this Section, if a Participant separates from the employment of an Employer or Affiliated Company for any reason other than his or her Retirement, Permanent Disability, death or transfer to the employment of another Employer or Affiliated Company, the Accounts of such Participant shall be retained in trust and shall continue to be credited with applicable earnings as provided in Section 4.3, and the Vested Interest of such Participant shall be distributed to him or her by the Trustee at the direction of the Committee in accordance with Section 6.2(a) as soon as practicable after his or her Normal Retirement Date (or, if the Participant dies prior to such date, the Vested Interest of such Participant shall be distributed upon his or her death in accordance with Section 6.3); provided, however, that (i) each such Participant shall have the right

to elect on a form prescribed by the Committee to receive an early distribution of his or her Vested Interest as soon as practicable and (ii) the Committee shall require an early distribution of any such Participant's Vested Interest which does not exceed $5,000 in the form of a single distribution. The Vested Interest of a Participant who elects to receive an early distribution shall be distributed to him or her in the same manner as provided in Section 6.2(a) for a distribution upon Retirement or Permanent Disability. Any provision of this Plan to the contrary notwithstanding, for purposes of this Article a Participant shall not be treated as having separated from the employment of an Employer or Affiliated Company prior to such time that a distribution can be made to such Participant in accordance with Section 401(k) of the Code and the regulations thereunder. For purposes of determining whether the value of a Participant's Vested Interest exceeds $5,000, the value of a Participant's Vested Interest shall be determined without regard to the value of the Participant's Rollover Account.

(b) Any provision of subsection (a) of this Section to the contrary notwithstanding, except as otherwise provided in this subsection (b), if a Participant's whose Vested Interest exceeds $5,000 separates from the employment of an Employer or Affiliated Company for any reason other than his or her Retirement, Permanent Disability, death or transfer to the employment of another Employer or Affiliated Company, such Participant's Matching Plan Account, Mesa Premium Account, Prior Plan Employer Account and/or Prior Plan Pre-Tax Account shall be distributed to such Participant by the Trustee at the direction of the Committee upon such Participant's Normal Retirement Date by payment of the entire amount in the form of a Qualified Joint and Survivor Annuity contract to be purchased from a company selected by the Committee and commencing in payment as soon as practicable thereafter (or, if the Participant dies prior to his or her Normal Retirement Date, the Vested Interest of such Participant under the Plan shall be distributed upon his or her death in accordance with Section

6.3); provided, however, that each such Participant shall have the right to elect on a form prescribed by the Committee to receive an early distribution of the amount credited to his or her Matching Plan Account, Mesa Premium Account, Prior Plan Employer Account and/or Prior Plan Pre-Tax Account as soon as practicable after such election. If a Participant elects under this subsection (b) to receive an early distribution, such distribution shall be made in the form of (i) a Qualified Joint and Survivor Annuity contract to be purchased from a company selected by the Committee and commencing in payment as soon as practicable following such election, or (ii) upon satisfaction of the notice and waiver requirements of Section 6.2(b), in accordance with subsection (a) of this Section.

Section 6.5 Forfeitures.

(a) Unless sooner forfeited as provided below, any unvested portion of the Accounts of a Participant who separates from the employment of an Employer or Affiliated Company for any reason other than his or her Retirement, Permanent Disability, death or transfer to the employment of another Employer or Affiliated Company shall be

forfeited upon the earlier of the date of such Participant's death or the date such Participant incurs five consecutive One Year Breaks in Service unless such Participant is reemployed by an Employer or Affiliated Company prior to such date.

(b) If a Participant receives a complete distribution of his or her Vested Interest under Section 6.4 by the close of the second Plan Year following the Plan Year in which his or her separation from employment occurred, any portion of such Participant's Accounts which is not vested at the time of such distribution shall be forfeited at such time. If a Participant who separates from the employment of an Employer or Affiliated Company for any reason other than his or her Retirement, Permanent Disability, death or transfer to the employment of another Employer or Affiliated Company, is not entitled to receive any distribution from the Plan due to the fact that such Participant has no Vested Interest, such Participant shall be deemed to have received a distribution from the Plan of his or her entire Vested Interest under the Plan and any amount credited to such Participant's Accounts shall be forfeited at the time of such separation from employment. If a Participant, any portion of whose Accounts is forfeited pursuant to this subsection (b), is reemployed as a Covered Employee prior to incurring five consecutive One Year Breaks in Service, the amount so forfeited shall be restored to such individual's Accounts, out of current-year forfeitures or, if such forfeitures are insufficient, by an additional Employer contribution; provided, however, that no amount shall be restored to the Accounts of an individual who previously received a distribution of the vested portion of such Accounts unless he or she repays to the Plan, while a Covered Employee and within five years of the date of such reemployment, the full amount previously distributed from such Accounts for crediting to his or her Accounts.

(c) If a Participant who has not yet incurred five consecutive One Year Breaks in Service receives a distribution under Section 6.4 after the end of the second Plan Year following the year in which his or her separation from employment occurred, any portion of such Participant's Accounts which is not vested at the time of such distribution shall be retained in such Account and shall be forfeited upon the earlier of the date of such Participant's death or the date such Participant incurs five consecutive One Year Breaks in Service unless such Participant is reemployed by an Employer or Affiliated Company prior to such date. If a Participant receives a distribution from the Plan after the end of the second Plan Year following the year in which his or her separation from employment occurred and is reemployed by an Employer or Affiliated Company prior to incurring five consecutive One Year Breaks in Service, then the unvested balance in his or her Accounts shall be transferred to a segregated account for such Participant and the amount that the Participant is entitled to receive from such segregated account as of any later date shall be an amount equal to X, which amount shall be determined in accordance with the following formula: $X = P(AB + D) - D$, where P is the Participant's vested percentage at such later date, AB is the amount in his or her segregated account at such later date, and D is the amount distributed to the Participant in connection with his or her earlier separation from employment.

(d) All amounts forfeited under the Plan shall be credited to a forfeiture account and invested by the Trustee at the direction of the Committee in its discretion until such forfeited amounts and any earnings attributable thereto are applied in accordance with Section 3.8.

Section 6.6 In-Service Withdrawals.

(a) A Participant in the employ of an Employer may make --

(i) a withdrawal of all or a portion (in multiples of 10% or in whole dollar amounts) of the total amount credited to his or her After-Tax Account, Mesa After-Tax Account or Rollover Account;

(ii) if the Participant has attained the age of 59 1/2, a withdrawal of all or a portion (in multiples of 10% or in whole dollar amounts) of the total vested amount credited to his or her Accounts (other than his or her Matching Plan Account and Mesa Premium Account); or

(iii) a hardship withdrawal of such amount as the Committee shall determine to be necessary to satisfy an immediate and heavy financial need of such Participant from his or her Pre-Tax Account and Prior Plan Pre-Tax Account, other than earnings credited to either such Account for any period of time after December 31, 1988, and qualified nonelective contributions allocated to either such Account;

provided, however, that (i) no withdrawal may be made unless notice of such withdrawal is delivered to or in the manner prescribed by the Committee by the withdrawing Participant within such period of time prior to the effective date thereof as the Committee may prescribe in its discretion, (ii) no withdrawal may be made by a Participant to whom a loan from the Trust is then outstanding unless the Committee is satisfied that such loan will remain nontaxable and fully secured by the withdrawing Participant's Vested Interest following such withdrawal, and (iii) withdrawals from the Prior Plan Pre-Tax Account and Prior Plan Employer Account may be made only pursuant to the notice and consent requirements of Section 6.2(b). The Committee shall direct the Trustee to distribute any withdrawn amount to such Participant as soon as practicable following the effective date of the withdrawal. Any withdrawal from an Account pursuant to this Section shall be taken proportionally from each Investment Fund in which such Account is invested. The Committee may prescribe uniform and nondiscriminatory rules and procedures limiting the number of times that a Participant may make withdrawals during a Plan Year and the minimum amount that a Participant may withdraw on any single occasion.

(b) A hardship withdrawal will be considered to be made on account of an immediate and heavy financial need of a Participant only if the Committee determines that such withdrawal is on account of (i) expenses for medical care described in Section 213(d) of the Code

previously incurred by such Participant or his or her spouse or dependents (as defined in Section 152 of the Code) or necessary for such individuals to obtain such care, (ii) costs directly related to the purchase of a principal residence for such Participant (excluding mortgage payments), (iii) payment of tuition and related educational fees for the next 12 months of post-secondary education for such Participant or his or her spouse, children or dependents (as so defined), or (iv) payments necessary to prevent the eviction of such Participant from his or her principal residence or foreclosure on the mortgage of such residence.

(c) A hardship withdrawal will be considered to be necessary to satisfy an immediate and heavy financial need of a Participant only if the Committee determines that (i) the amount of such withdrawal is not in excess of the amount of such need plus any amounts necessary to pay any federal, state or local income taxes or penalties reasonably anticipated to result from the withdrawal, and (ii) such Participant has obtained all distributions and withdrawals, other than hardship withdrawals, and all nontaxable loans currently available under all plans maintained by the Employers.

(d) Any provision of this Plan to the contrary notwithstanding, if a Participant makes a hardship withdrawal, (i) no Pre-Tax Contributions or Pre-Tax Bonus Contributions shall be made on behalf of such Participant for 6 months after receipt of such withdrawal and no contributions shall be made by or on behalf of such Participant to any other deferred compensation plan maintained by an Employer or Affiliated Company for 6 months after receipt of such withdrawal and (ii) the Total Pre-Tax Contributions made on behalf of such Participant for the calendar year immediately following the calendar year of such withdrawal shall not exceed the amount by which the limitation under Section 402(g) of the Code for such next calendar year exceeds the amount of the Total Pre-Tax Contributions made on behalf of such Participant for the calendar year of such withdrawal.

Section 6.7 Distributions to Minors and Persons Under Legal Disability. If any distribution under the Plan becomes payable to a minor or other person under a legal disability, such distribution may be made to the duly appointed guardian or other legal representative of the estate of such minor or person under legal disability.

Section 6.8 Benefits Payable to Missing Participant or Beneficiary. If the Committee cannot locate a Participant or beneficiary entitled to a distribution under this Plan within a period of three years after such Participant or beneficiary becomes entitled to the distribution, the amounts credited to the Accounts of such Participant or beneficiary shall be forfeited; provided, however, that if a claim for any such forfeited amounts is subsequently made by any person entitled to the distribution, such forfeited amounts shall be restored (without adjustment for earnings or appreciation) out of current-year forfeitures, or if such forfeitures are insufficient, by an additional Employer contribution.

Section 6.9 Plan Loans.

(a) Subject to such conditions and limitations as the Committee may from time to time prescribe for application to all Participants and beneficiaries on a uniform basis, at the request of a Participant or beneficiary of a deceased Participant who is a party in interest (within the meaning of Section 3(14) of the Employee Retirement Income Security Act of 1974, as amended) with respect to the Plan (hereinafter called the "Borrower"), the Committee shall direct the Trustee to loan to such Borrower from his or her Accounts (other than the Borrower's Matching Plan Account and Mesa Premium Account) an amount of money which, when added to the total outstanding balance of all other loans to such Borrower from the Plan or from a qualified employer plan (within the meaning of Section 72(p) of the Code) maintained by an Employer or Affiliated Company, does not exceed the lesser of (i) $50,000 (reduced, however, by the excess, if any, of the highest total outstanding balance of all such other loans during the one-year period ending on the day before the date such loan is made, over the outstanding balance of all such other loans on the date such loan is made), or (ii) one-half of such Participant's Vested Interest under the Plan (or, in the case of a loan to a beneficiary, one-half of such beneficiary's Accounts).

(b) Any such loan made to a Borrower shall be evidenced by a promissory note or other evidence of indebtedness payable to the Trustee, shall bear a reasonable rate of interest, shall be secured by one-half of the Participant's vested interest under the Plan (or, in the case of a loan to a beneficiary, by one-half of such beneficiary's Accounts), shall be repayable in substantially equal payments no less frequently than quarterly and shall be repayable within five years or, in the case of a loan that is to be used to acquire any dwelling unit which within a reasonable period of time is to be used as the principal residence of the Participant, within such period greater than five years as shall be determined by the Committee in its absolute discretion.

(c) Any provision of this Plan to the contrary notwithstanding, (i) the promissory note or other evidence of indebtedness evidencing any such loan shall be held by the Trustee as a segregated investment allocated to and made solely for the benefit of the Account of the Borrower from which such loan was made, and (ii) no loan shall be made to a married Participant from a Prior Plan Pre-Tax Account or Prior Plan Employer Account unless the spouse of such Participant consents in writing thereto within the 90-day period preceding the date such loan is made and such consent is witnessed by a notary public.

Section 6.10 Qualified Domestic Relations Orders. Any provision of this Plan to the contrary notwithstanding:

(a) The Committee shall establish and maintain for each alternate payee named with respect to a Participant under a domestic relations order which is determined by the Committee to be a qualified domestic relations order (as defined in Section 414(p) of the Code)

such separate Accounts as the Committee may deem to be necessary or appropriate to reflect such alternate payee's interest in the Accounts of such Participant. Such alternate payee's Accounts shall be credited with the alternate payee's interest in the Participant's Accounts as determined under such qualified domestic relations order. The alternate payee may change investment direction with respect to his or her Account balances in accordance with Section 4.2 in the same manner as the Participant.

(b) Except to the extent otherwise provided in the qualified domestic relations order naming an alternate payee with respect to a Participant, (i) the alternate payee may designate a beneficiary on a form prescribed by and filed with or as directed by the Committee, (ii) if no such beneficiary is validly designated or if the designated beneficiary is a person who predeceases the alternate payee, the beneficiary of the alternate payee shall be the alternate payee's estate, and (iii) the beneficiary of the alternate payee shall be accorded under the Plan all of the rights and privileges of the beneficiary of a Participant.

(c) An alternate payee named with respect to a Participant shall be entitled to receive a distribution from the Plan in accordance with the qualified domestic relations order naming such alternate payee. Such distribution may be made only in a form provided under the Plan and shall include only such amounts as are vested. If a qualified domestic relations order so provides, a lump sum distribution of the total vested amount credited to the alternate payee's Accounts may be made to the alternate payee at any time prior to the date the Participant named in such qualified domestic relations order attains his or her earliest retirement age (as defined in Section 414(p)(4)(B) of the Code). To the extent provided by a qualified domestic relations order, the alternate payee named with respect to a Participant may make withdrawals (other than hardship withdrawals) from his or her Accounts in accordance with Article VI in the same manner as the Participant with respect to whom such alternate payee was named under said qualified domestic relations order.

(d) If a portion of any unvested amount credited to the Employer Account or Matching Plan Account of a Participant named in the qualified domestic relations order is credited to the Employer Account or Matching Plan Account, whichever is applicable, of the alternate payee named in such qualified domestic relations order, the portion credited to the alternate payee's Employer Account or Matching Plan Account shall vest and/or be forfeited at the same time and in the same manner as the Participant's Employer Account or Matching Plan Account, whichever is applicable.

Section 6.11 Transfer of Eligible Rollover Distribution. If a Participant is entitled to receive an eligible rollover distribution (as defined in Section 402(c) of the Code and the regulations thereunder) from the Plan, such Participant may elect to have the Committee direct the Trustee to transfer the entire amount of such distribution directly to any of the following "eligible retirement plans" specified by such Participant: an individual retirement account described in Section 408(a) of the Code, an individual retirement annuity described in Section 408(b) of the Code (other than an

endowment contract), a defined contribution plan qualified under Section 401(a) of the Code the terms of which permit rollover contributions or an annuity plan described in Section 403(a) of the Code. If the surviving spouse of a deceased Participant is entitled to receive an eligible rollover distribution from the Plan, such surviving spouse may elect to have the Committee direct the Trustee to transfer the entire amount of such distribution directly to either an individual retirement account described in Section 408(a) of the Code or an individual retirement annuity described in Section 408(b) of the Code (other than an endowment contract) specified by such surviving spouse. If an alternate payee under a qualified domestic relations order (as defined in Section 414(p) of the Code) is the spouse or former spouse of the Participant specified in the qualified domestic relations order, this Section shall apply to such alternate payee as if the alternate payee were a Participant. A distributee of an eligible rollover distribution who is entitled to make an election under this Section may specify that some portion less than the entire amount of such distribution be transferred in accordance with this Section. The preceding provisions of this Section to the contrary notwithstanding, (i) an "eligible retirement plan" shall also mean an annuity contract described in Section 403(b) of the Code and an eligible plan under Section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state and which agrees to separately account for amounts transferred into such plan from this Plan, (ii) the definition of "eligible retirement plan" shall also apply in the case of a distribution to a surviving spouse, or to a spouse or former spouse who is the alternate payee under a qualified domestic relations order, as defined in Section 414(p) of the Code, (iii) any amount that is distributed on account of hardship shall not be an eligible rollover distribution and the distributee may not elect to have any portion of such a distribution paid directly to an eligible retirement plan, and (iv) a portion of a distribution shall not fail to be an eligible rollover distribution merely because the portion consists of after-tax employee contributions which are not includible in gross income, provided that such portion may be transferred only to an individual retirement account or annuity described in Section 408(a) or (b) of the Code, or to a qualified defined contribution plan described in Section 401(a) or 403(a) of the Code that agrees to separately account for amounts so transferred, including separately accounting for the portion of such distribution which is includible in gross income and the portion of such distribution which is not so includible.

ARTICLE VII.

PLAN ADMINISTRATION

Section 7.1 401(k) and Matching Plan Committee. The plan administrator of the Plan shall be a 401(k) and Matching Plan Committee composed of at least three individuals appointed by the Board of Directors of the Company. Each member of the Committee so appointed shall serve in such office until his or her death, resignation or removal by the Board of Directors of the Company. The Board of Directors of the Company may remove any member of the Committee at any time by giving written notice thereof to the members of the Committee. Vacancies shall likewise be filled from time to time by the Board of Directors of the

Company. The members of the Committee shall receive no remuneration from the Plan for their services as Committee members.

Section 7.2 Powers, Duties and Liabilities of the Committee. The Committee shall have discretionary and final authority to interpret and implement the provisions of the Plan, including without limitation authority to determine eligibility for benefits under the Plan, and shall perform all of the duties and exercise all of the powers and discretion granted to it under the terms of the Plan. The Committee shall act by a majority of its members at the time in office and such action may be taken either by a vote at a meeting or in writing without a meeting. The Committee may by such majority action authorize any one or more of its members to execute any document or documents on behalf of the Committee, in which event the Committee shall notify the Trustee in writing of such action and the name or names of its member or members so authorized to act. Every interpretation, choice, determination or other exercise by the Committee of any discretion given either expressly or by implication to it shall be conclusive and binding upon all parties directly or indirectly affected, without restriction, however, on the right of the Committee to reconsider and redetermine such actions. In performing any duty or exercising any power herein conferred, the Committee shall in no event perform such duty or exercise such power in any manner which discriminates in favor of Highly Compensated Employees. The Employers shall indemnify and hold harmless each member of the Committee against any claim, cost, expense (including attorneys' fees), judgment or liability (including any sum paid in settlement of a claim with the approval of the Employers) arising out of any act or omission to act as a member of the Committee appointed under this Plan, except in the case of willful misconduct.

Section 7.3 Rules, Records and Reports. The Committee may adopt such rules and procedures for the administration of the Plan as are consistent with the terms hereof, and shall keep adequate records of the Committee's proceedings and acts and of the status of the Participants' Accounts. The Committee may employ such agents, accountants and legal counsel (who may be agents, accountants or legal counsel for an Employer) as may be appropriate for the administration of the Plan. The Committee shall at least annually provide each Participant with a report reflecting the status of his or her Accounts in the Trust and shall cause such other information, documents or reports to be prepared, provided and/or filed as may be necessary to comply with the provisions of the Employee Retirement Income Security Act of 1974 or any other law.

Section 7.4 Administration Expenses and Taxes. Unless otherwise paid by the Employers in their absolute discretion, the Committee shall direct the Trustee to pay all reasonable and necessary expenses (including the fees of agents, accountants and legal counsel) incurred by the Committee in connection with the administration of the Plan. Should any tax of any character (including transfer taxes) be levied upon the Trust assets or the income therefrom, such tax shall be paid from and charged against the assets of the Trust.

ARTICLE VIII.

AMENDMENT AND TERMINATION

Section 8.1 Amendment. The Board of Directors of the Company shall have the right and power at any time and from time to time to amend this Plan, in whole or in part, on behalf of all Employers. Any such amendment made by the Board of Directors of the Company shall be made by or pursuant to a resolution duly adopted by the Board of Directors of the Company, and shall be evidenced by such resolution or by a written instrument executed by such person as the Board of Directors of the Company shall authorize for such purpose. With the consent of the Board of Directors of the Company and subject to such procedure as it may prescribe, the Board of Directors of each Employer shall have the right and power at any time and from time to time to amend this Plan, in whole or in part, with respect to the Plan's application to the Participants of the particular amending Employer and the assets held in the Trust for their benefit, or to transfer such assets or any portion thereof to a new trust for the benefit of such Participants. However, in no event shall any amendment or new trust permit any portion of the trust fund to be used for or diverted to any purpose other than the exclusive benefit of the Participants and their beneficiaries, nor shall any amendment or new trust reduce a Participant's Vested Interest under the Plan.

Section 8.2 Termination. The Board of Directors of the Company shall have the right and power at any time to terminate this Plan on behalf of all Employers, or to terminate this Plan as it applies to the Participants who are or were employees of any particular Employer, by giving written notice of such termination to the Committee and Trustee. Any provision of this Plan to the contrary notwithstanding, upon the termination or partial termination of the Plan as to any Employer, or in the event any Employer should completely discontinue making contributions to the Plan without formally terminating it, all amounts credited to the Accounts of the affected Participants of that particular Employer shall be fully vested.

Section 8.3 Benefit Plan Design Committee. Any action permitted to be taken by the Board with respect to the amendment of this Plan may be taken by the Benefit Plan Design Committee. The Benefit Plan Design Committee shall be composed of at least two individuals appointed by the Board of Directors of the Company. Each member of the Benefit Plan Design Committee so appointed shall serve in such office until his or her death, resignation or removal by the Board. The Board may remove any member of the Benefit Plan Design Committee at any time by giving written notice thereof to the members of the Benefit Plan Design Committee. Vacancies shall likewise be filled from time to time by the Board. The Benefit Plan Design Committee shall act by a majority of its members at the time in office and such action may be taken either by a vote at a meeting or in writing without a meeting.

ARTICLE IX.

TOP-HEAVY PROVISIONS

Section 9.1 Top-Heavy Definitions. Unless the context clearly indicates otherwise, when used in this Article:

(a) "Top-Heavy Plan" means this Plan if, as of the Determination Date, the aggregate of the Accounts of Key Employees under the Plan exceeds 60% of the aggregate of the Accounts of all Participants and former Participants under the Plan. The aggregate of the Accounts of any Participant or former Participant shall include any distributions (other than related rollovers or transfers from the Plan within the meaning of regulations under Section 416(g) of the Code) made from such individual's Accounts during the one-year period ending on the Determination Date, but shall not include any unrelated rollovers or transfers (within the meaning of regulations under Section 416(g) of the Code) made to such individual's Accounts after December 31, 1983; provided, however, that in the case of a distribution made for a reason other than separation from service, death, or disability, this provision shall be applied by substituting "five-year period" for "one-year period". The Account of any Participant or former Participant who (i) is not a Key Employee for the Plan Year in question but who was a Key Employee in a prior Plan Year, or (ii) has not completed an Hour of Service during the one-year period ending on the Determination Date, shall not be taken into account. The determination of whether the Plan is a Top-Heavy Plan shall be made after aggregating all other plans of an Employer and any Affiliated Company qualifying under Section 401(a) of the Code in which a Key Employee is a participant or which enables such a plan to meet the requirements of Section 401(a)(4) or 410 of the Code, and after aggregating any other plan of an Employer or Affiliated Company, which is not already aggregated, if such aggregation group would continue to meet the requirements of Sections 401(a)(4) and 410 of the Code and if such permissive aggregation thereby eliminates the top-heavy status of any plan within such permissive aggregation group. For purposes of determining the aggregate of the Accounts of any Participant or former Participant, the distributions included, as provided above, shall include distributions under a terminated plan which, had it not been terminated, would have been aggregated with the Plan under Section 416(g)(2)(A)(i) of the Code. The determination of whether this Plan is a Top-Heavy Plan shall be made in accordance with Section 416(g) of the Code.

(b) "Determination Date" means, for purposes of determining whether the Plan is a Top-Heavy Plan for a particular Plan Year, the last day of the preceding Plan Year.

(c) "Key Employee" means any Employee or former Employee (including a beneficiary of such Employee or former Employee) who at any time during the Plan Year that includes the Determination Date is:

(1) an officer of an Employer having Compensation for such Plan Year greater than $130,000 (as adjusted under Section 416(i)(1) of the Code for Plan Years beginning after December 31, 2002);

(2) a 5% owner of the Employer; or

(3) a 1% owner of the Employer having Compensation for such Plan Year of more than $150,000.

The determination of who is a Key Employee will be made in accordance with Section 416(i)(1) of the Code and the applicable regulations and other guidance of general applicability issued thereunder.

(d) "Non-Key Employee" means any Employee or former Employee (including a beneficiary of such Employee or former Employee) who is not a Key Employee.

Section 9.2 Minimum Contribution Requirement. Any provision of this Plan to the contrary notwithstanding, if the Plan is a Top-Heavy Plan for any Plan Year, then the Employers will contribute to the Employer Account of each Non-Key Employee who is both eligible to participate and in the employ of an Employer on the last day of such Plan Year, an amount which, when added to the total amount of Matching Contributions and forfeitures otherwise allocable under the Plan to such Non-Key Employee for such year, shall equal the lesser of (i) 3% of such Non-Key Employee's Compensation for such year or (ii) the amount of contributions (including Total Pre-Tax Contributions) and forfeitures (expressed as a percentage of Compensation) allocable under the Plan for or on behalf of the Key Employee for whom such percentage is the highest for the Plan Year after taking into account contributions under other defined contribution plans maintained by the Employer in which a Key Employee is a participant (as well as any other plan of an Employer which enables such a plan to meet the requirements of Section 401(a)(4) or 410 of the Code); provided, however, that no minimum contribution shall be made for a Non-Key Employee under this Section for any Plan Year if the Employer maintains another qualified plan under which a minimum benefit or contribution is being accrued or made for such Plan Year for the Non-Key Employee in accordance with Section 416(c) of the Code. A Non-Key Employee who is not a Participant, but for whom a contribution is made pursuant to this Section, shall be accorded all of the rights and privileges of a Participant under the Plan except that no contributions (other than contributions pursuant to this Section) shall be made for or on behalf of such Non-Key Employee until he or she meets the eligibility and participation requirements of Article II.

Section 9.3 Minimum Vesting Schedule. Any provision of this Plan to the contrary notwithstanding, if the Plan is a Top-Heavy Plan for any Plan Year, then effective as of the first day of such Plan Year with respect to Participants who complete an Hour of Service on or after such day, the vesting schedule provided in Section 5.2 shall be applied to that portion of such Participants' Employer Account which is attributable to any amounts credited to

his or her Employer Nonelective Contribution Account under the Superseded Plan as in effect on September 30, 1997, as if to read as follows:

Period of Service Completed by Participant	Percentage Vested
Less than 3 years	None
3 or more years	100%

ARTICLE X.

MISCELLANEOUS GENERAL PROVISIONS

Section 10.1 Spendthrift Provision. No right or interest of any

Participant or beneficiary under the Plan may be assigned, transferred or alienated, in whole or in part, either directly or by operation of law, and no such right or interest shall be liable for or subject to any debt, obligation or liability of such Participant or beneficiary; provided, however, that nothing herein shall prevent the payment of amounts from a Participant's Accounts under the Plan in accordance with the terms of a court order which the Committee has determined to be a qualified domestic relations order (as defined in Section 414(p) of the Code).

Section 10.2 Claims Procedure. If any person (hereinafter called the "Claimant") feels that he or she is being denied a benefit to which he or she is entitled under the Plan, such Claimant may file a written claim for said benefit with any member of the Committee. Within 60 days of the receipt of such claim the Committee shall determine and notify the Claimant as to whether he or she is entitled to such benefit. Such notification shall be in writing and, if denying the claim for benefit, shall set forth the specific reason or reasons for the denial, make specific reference to the pertinent provisions of the Plan, and advise the Claimant that he or she may, within 60 days of the receipt of such notice, in writing request to appear before the Committee for a hearing to review such denial. Any such hearing shall be scheduled at the mutual convenience of the Committee or its designated representative and the Claimant, and at such hearing the Claimant and/or his or her duly authorized representative may examine any relevant documents and present evidence and arguments to support the granting of the benefit being claimed. The final decision of the Committee with respect to the claim being reviewed shall be made within 60 days following the hearing thereon and the Committee shall in writing notify the Claimant of its final decision, again specifying the reasons therefor and the pertinent provisions of the Plan upon which such decision is based. The final decision of the Committee shall be conclusive and binding upon all parties having or claiming to have an interest in the matter being reviewed.

Section 10.3 Maximum Contribution Limitation. Any provision of this Plan to the contrary notwithstanding (except to the extent permitted under Section 3.3 of the Plan and Section 414(v) of the Code, if applicable), the sum of (i) the Employer contributions, (ii) the forfeitures, and (iii) the

Participant contributions (excluding rollover contributions and employee contributions to a simplified employee pension allowable as a deduction, each within the meaning specified in Section 415(c)(2) of the Code), allocated to a Participant with respect to a Plan Year shall in no event exceed the lesser of $40,000 (as adjusted for increases in the cost-of-living under Section 415(d) of the Code) or 100% of such Participant's Compensation for that year. For the purposes of applying the limitation imposed by this Section, each Employer and its Affiliated Companies shall be considered a single employer, and all defined contribution plans (meaning plans providing for individual accounts and for benefits based solely upon the amounts contributed to such accounts and any forfeitures, income, expenses, gains and losses allocated to such accounts) described in Section 415(k) of the Code, whether or not terminated, maintained by an Employer or its Affiliated Companies shall be considered a single plan. If the total amount allocable to a Participant's Accounts for a particular Plan Year would, but for this sentence, exceed the foregoing limitation, such Participant's After-Tax Contributions shall first be distributed and then, to the extent necessary, Total Pre-Tax Contributions shall be distributed first from any Pre-Tax Bonus Contributions and then from Pre-Tax Contributions. Any Matching Contributions corresponding to any distributed Pre-Tax Contributions shall be credited to a suspense account and thereafter reallocated (prior to the allocation of subsequent forfeitures and the making of any additional contributions to the Plan) to reduce the earliest subsequent Matching Contributions an Employer would otherwise be required to make to the Plan pursuant to Section 3.2 for such year and the next succeeding Plan Year. No adjustment shall be made to such suspense account to reflect income, profits and losses, expenses or other transactions affecting the Plan. Any Pre-Tax Contributions or Pre-Tax Bonus Contributions distributed to a Participant pursuant to this Section shall not be taken into account in determining such Participant's actual deferral percentage for purposes of Section 3.7.

Section 10.4 Employment Noncontractual. The establishment of this Plan shall not enlarge or otherwise affect the terms of any Employee's employment with an Employer and an Employer may terminate the employment of any Employee as freely and with the same effect as if this Plan had not been adopted.

Section 10.5 Limitations on Responsibility. The Employers do not guarantee or indemnify the Trust against any loss or depreciation of its assets which may occur, nor guarantee the payment of any amount which may become payable to a Participant or his or her beneficiaries pursuant to the provisions of this Plan. All payments to Participants and their beneficiaries shall be made by the Trustee at the direction of the Committee solely from the assets of the Trust and the Employers shall have no legal obligation, responsibility or liability for any such payments.

Section 10.6 Merger or Consolidation. In no event shall this Plan be merged or consolidated into or with any other plan, nor shall any of its assets or liabilities be transferred to any other plan, unless each Participant would be entitled to receive a benefit if the plan in which he or she then participates terminated immediately following such merger, consolidation or transfer, which is equal to or greater than the benefit he or she would have been entitled to receive if the Plan had been terminated immediately prior to such merger, consolidation or transfer.

Section 10.7 Applicable Law. This Plan shall be governed and construed in accordance with the internal laws (and not the principles relating to conflicts of laws) of the State of Texas except where superseded by federal law.

Section 10.8 USERRA Compliance. Notwithstanding any provision of this Plan to the contrary, contributions, benefits and service credit with respect to qualified military service will be provided in accordance with Section 414(u) of the Code.

IN WITNESS WHEREOF, this restatement has been executed as of this ____ day of December, 2001, to be effective as of January 1, 2002.

PIONEER NATURAL RESOURCES USA, INC.

By____
Larry Paulsen, Vice President - Administration

EXHIBIT 21.1

SUBSIDIARIES OF THE COMPANY

State or Jurisdiction of Organization	Subsidiaries
Delaware	Bridge Oil (U.S.A.) Inc.
Delaware	DMLP Co.
Netherlands	D, P & D Investments B.V.
Delaware	Mesa Environmental Ventures Co.
Texas	Mesa Offshore Royalty Partnership
Delaware	Parker & Parsley Argentina, Inc.
Australia	Parker & Parsley Petroleum Australia Holdings Pty Limited
Australia	Parker & Parsley Petroleum Australia Pty Limited
Delaware	Pioneer International Resources Company
Texas	Pioneer Natural Gas Company
Delaware	Pioneer Natural Resources Alaska, Inc.
Cayman Islands	Pioneer Natural Resources Anaguid Ltd.
Argentina	Pioneer Natural Resources (Argentina) S.A.
Cayman Islands	Pioneer Natural Resources Borj El Khadra Ltd.
Canada	Pioneer Natural Resources Canada Inc.
Cayman Islands	Pioneer Natural Resources (Cayman) Ltd.
Texas	Pioneer Natural Resources Scholarship Foundation
South Africa	Pioneer Natural Resources South Africa (Pty) Limited
Argentina	Pioneer Natural Resources (Tierra Del Fuego) S.A.
Cayman Islands	Pioneer Natural Resources Tunisia Ltd.
Delaware	Pioneer Natural Resources USA, Inc.
Bahamas	Pioneer Resources Africa, Ltd.
Bahamas	Pioneer Resources Gabon - Olowi Ltd.
Texas	Pioneer Uravan, Inc.
Delaware	Westpan NGL LP
Delaware	Westpan Properties, Inc.
Nevada	Westpan Resources Company
Delaware	Westpan Resources LP

Partnerships that Pioneer Natural Resources USA, Inc. is the managing general partner

Delaware	Parker & Parsley 87-A Conv., Ltd.
Delaware	Parker & Parsley Private Investment 88, L.P.
Delaware	Parker & Parsley Private Investment 89, L.P.
Delaware	Parker & Parsley 90 Spraberry Private Development, L.P.
Texas	Midkiff Development Drilling Program, Ltd.

EXHIBIT 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statements (No. 333-88438, No. 333-35087, No. 333-35165, No. 333-39153, No. 333-39249, No. 33-44851, No. 333-35085 and No. 333-35175) on Form S-8 and (No. 333-88478, No. 333-42315, No. 333-44439 and No. 333- 39381) on Form S-3 of Pioneer Natural Resources Company and the related Prospectuses of our report dated January 24, 2003, with respect to the consolidated financial statements of Pioneer Natural Resources Company included in this Annual Report on Form 10-K for the year ended December 31, 2002.

Ernst & Young LLP

Dallas, Texas
February 19, 2003

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in the Registration Statements (No. 333-88438, No. 333-35087, No. 333-35165, No. 333-39153, No. 333-39249, No. 33-44851, No. 333-35085 and No. 333-35175) on Form S-8 and (No. 333-88478, No. 333-42315, No. 333-44439 and No. 333- 39381) on Form S-3 of Pioneer Natural Resources Company and the related Prospectuses of the reference of Netherland, Sewell & Associates, Inc. in the Annual Report on Form 10-K for the year ended December 31, 2002 of Pioneer Natural Resources Company and its subsidiaries, filed with the Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Frederic D. Sewell

Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
February 17, 2003

EXHIBIT 23.3

CONSENT OF GAFFNEY, CLINE & ASSOCIATES, INC.

As the independent reserve engineers for Pioneer Natural Resources Company (Pioneer), Gaffney, Cline & Associates, Inc. (GCA) hereby confirms that it has granted and not withdrawn its consent to the reference in the Registration Statements (No. 333-88438, No. 333-35087, No. 333-35165, No. 333-39153, No. 333-39249, No. 33-44851, No. 333-35085 and No. 333-35175) on Form S-8 and (No. 333-88478, No. 333-42315, No. 333-44439 and No. 333-39381) on Form S-3 as disclosed by Pioneer in its Form 10-K submission to the United States Securities and Exchange Commission for the period ending December 31, 2002.

GAFFNEY, CLINE & ASSOCIATES, INC.

Houston, Texas
February 19, 2003