PIONEER NATURAL RESOURCES

2005 Annual Report

Fellow shareholders,

As we look back on 2005 in years to come, I'm convinced that we'll see that the year marked an important turning point for Pioneer. We launched a number of initiatives during the year to refocus our strategy on North America providing the same type of opportunities on which our predecessor companies were founded over 20 years ago. With this year's annual report to shareholders, I will explain the reasons for refocusing our strategy, talk about our current plans and reacquaint you with the areas of our operations, their natural beauty and the opportunities they hold for Pioneer. In many ways, 2005 was a record year for Pioneer:

- Record cash flow from operations of $1.3 billion
- A 54% increase in earnings per diluted share
- An 820–well drilling program
- The repurchase of 20 million outstanding common shares

We benefited from strong oil and gas prices, and the market price of our common stock rose 46% during 2005. Over the last five years, the market price of Pioneer common stock has risen 160% on the strong production growth generated by our exploration programs in the deepwater Gulf of Mexico (GOM) and offshore South Africa.

More recent deepwater GOM exploration results have been less encouraging, and the costs and risks of drilling wells there have risen significantly. Production from our existing deepwater GOM fields began declining during 2005 and limited our ability to increase total company production going forward. We also saw little upside in our oil and gas properties in Argentina, especially considering the government controls on commodity prices.

At the same time, our exploration and exploitation teams were uncovering and testing new onshore North American resource plays that, like our foundation assets, have the potential to deliver strong, predictable production and proved reserve growth. We've had success in expanding the Edwards Reef play beyond our Pawnee field in South Texas. We entered several promising unconventional opportunities through the merger with Evergreen Resources in 2004, in southern Alberta, Canada and in several basins in the Rocky Mountains, and have expanded our acreage positions in each of the areas. In southern Alberta, we're in our second year of aggressively developing coal bed methane (CBM) in the Horseshoe Canyon area and have several CBM tests and pilot programs planned for 2006 in three basins in the Rockies.

Considering these and other opportunities, we announced several initiatives in September 2005 aimed at exiting the deepwater GOM and Argentina and refocusing more of our efforts and investments in onshore North American resource plays. While we plan to continue our higher-impact exploration programs in Alaska and West Africa, we are reducing our overall investment in higher-risk exploratory drilling.

I am pleased to report that we've had success on each of the initiatives, ultimately resulting in:

- An agreement to sell all of our Argentina properties for $675 million, which is expected to close in March 2006
- An agreement to sell our deepwater GOM assets, other than the Clipper discovery announced in late 2005, for $1.3 billion, which is also expected to close in March 2006
- An additional $641 million of share repurchases in 2005 for total share repurchases of $941 million for the year
- Plans to initiate a $359 million share repurchase program upon closing the asset sales
- A 2006 capital budget of $1.3 billion with 80% allocated to onshore North American activities
- A reduction in higher-impact, high-risk exploration to 10% of the 2006 capital budget versus approximately 30% in 2005
- A 20% increase in the semiannual dividend paid on common shares outstanding to $0.12 per share

Upon completion of the divestitures, our North American assets will represent approximately 98% of proved reserves and 92% of daily production. Pioneer will be a smaller company with fewer shares outstanding, minimal debt and an outlook for strong, profitable production growth.

Over the next five years, we expect to achieve compounded annual production growth in excess of 10% through our development drilling program, with significant upside as we establish new resource plays, acquire incremental core area assets or have success in our higher-impact exploration program. We plan to primarily concentrate on predictable oil and gas basins in North America that can deliver strong, consistent growth while continuing the development of fields in Alaska, Tunisia and South Africa that are expected to add significant production within two years.

We are pursuing opportunities in several conventional and unconventional resource plays and will continue to selectively expand our acreage positions in these plays and our core areas. By redirecting the efforts of our people who were previously focused on our deepwater GOM assets, we have expanded our exploitation and business development efforts to support our core area expansion efforts and the evaluation of new resource plays.

Initiating changes such as these is extremely challenging and requires significant effort on the part of many employees. I'm proud of the way our employees rose to the challenge, and we all appreciate their efforts. I'm also proud of Pioneer's strong sense of community, which was evident as many employees joined the Company this year in giving generously to assist the less fortunate and the victims of the hurricanes.

The health and safety of our employees and the environments in which we work are a top priority at Pioneer, and again in 2005, our people demonstrated leadership in these areas.

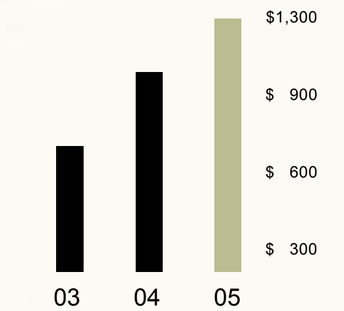
In December 2005, long-time board member James L. Houghton retired from the board of directors. We appreciate his years of service and commitment to Pioneer's success.

The initiatives we undertook during 2005 created a period of temporary uncertainty for our investors. We knew it would take time to deliver on the initiatives and demonstrate success under the new strategy, and we appreciate your patience. I am confident in our ability to again deliver top-tier performance and look forward to earning your continued support.

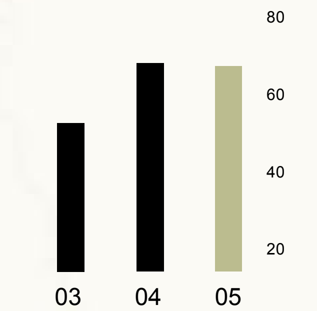
Scott D. Sheffield

Scott D. Sheffield
Chairman and CEO

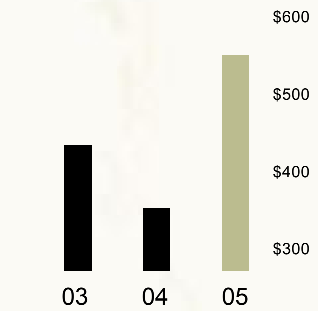
CASH FLOW FROM OPERATIONS
(MILLIONS)



ANNUAL PRODUCTION
(MILLION BARRELS OIL EQUIVALENT)



NET INCOME
(MILLIONS)



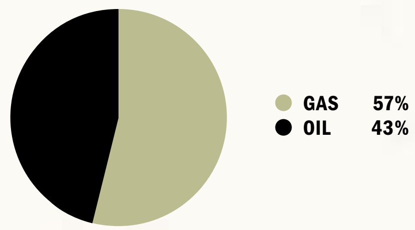
2005 ACCOMPLISHMENTS

- Record cash flow from operations of $1.3 billion
- Net income per diluted share up 54%
- Drilled 820 wells with 95% success
- Repurchased 20 million shares
- Increased the dividend paid on common shares by 20%

FIVE-YEAR GROWTH PLAN

- Greater than 10% average annual growth expected from lower-risk drilling and development
- Significant upside with success in establishing new resource plays, acquiring incremental core area assets or with higher-impact exploration program

PROVED OIL AND GAS RESERVES
987 MILLION BARRELS OIL EQUIVALENT*



2006 CAPEX BUDGET
$1.3 BILLION

*Proved reserves as of 12/31/05, 82% of reserves audited by Netherland, Sewell & Associates, Inc.

NORTH AMERICA FOCUS

2006 PLANS

Alaska North Slope
Developing Oooguruk project
Planning 3 exploration wells

Alaska Cook Inlet
Evaluating 3-D seismic for mid-year decision on developing Cosmopolitan project

Northeast British Columbia
Planning 50 wells in Chinchaga field

South Central Alberta
Planning 200 wells in Horseshoe Canyon CBM play
Establishing Mannville CBM pilot programs in 3 areas

Rocky Mountains
CBM tests and pilot programs in Uinta, Piceance and Sand Wash basins

Southern Colorado
Planning 330 CBM wells in Raton field

Northern Louisiana & Mississippi
Testing new unconventional gas plays

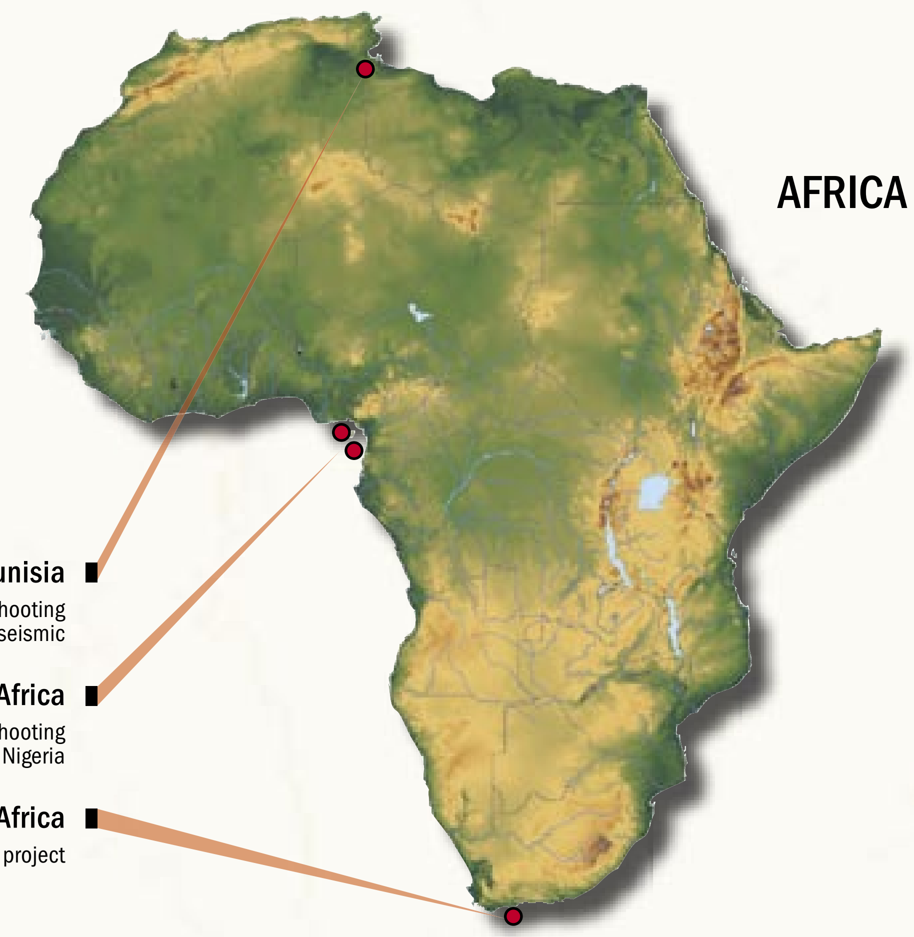
West Texas
Planning 350 wells in Spraberry field

South Texas
Drilling 15 to 20 wells in Pawnee field and 15 to 20 low-risk exploration wells to test Edwards Reef expansion

Gulf Coast
Evaluating 4 recent Shelf discoveries

A STRATEGY FOR PROFITABLE GROWTH

- Focusing on predictable oil and gas basins in North America that can deliver strong, consistent growth
- Adding new unconventional CBM and tight gas resource plays in North America
- Developing sizable discoveries offshore Alaska and South Africa
- Working to commercialize several discovered resources
- Shifting exploration focus to lower-risk resource plays onshore North America
- Continuing selective higher-impact exploration for longer-term upside
- Continuing to pursue acquisition opportunities to expand core areas

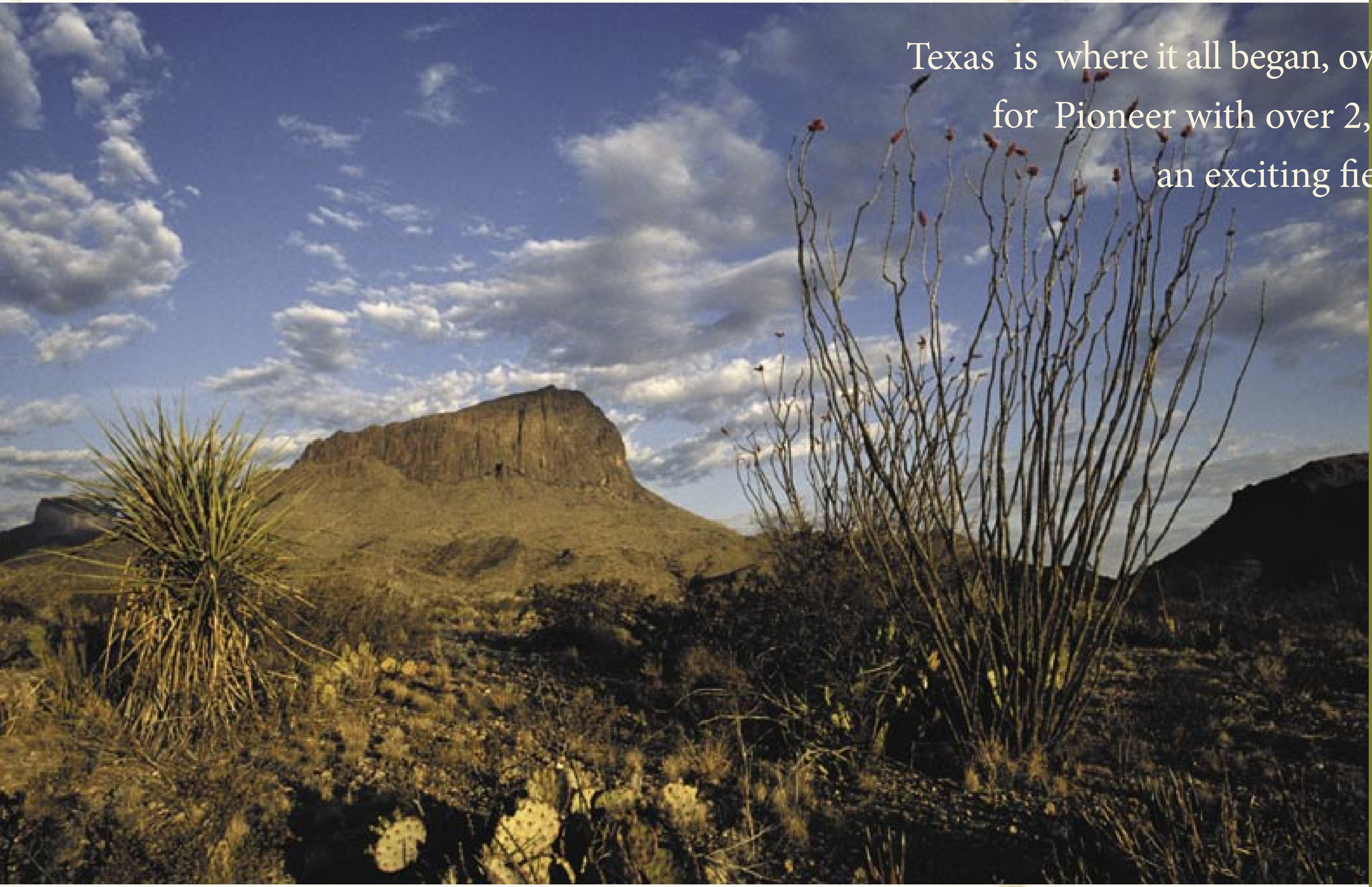


Southern Tunisia
Expanding drilling program and shooting new 3-D seismic

West Africa
Drilling exploration well and shooting new 3-D seismic offshore Nigeria

South Africa
Developing South Coast Gas project

When it comes to solid foundation assets, Pioneer's West Texas Spraberry field, with its long-lived oil and gas reserves, stable production and low maintenance capital cost, meets the requirements.



Texas is where it all began, over 25 years ago, and is still a cornerstone for Pioneer with over 2,500 drilling locations in West Texas and an exciting field expansion underway in South Texas.

We are the largest producer in the field and have set the standards for best practices in development and operations. This resource play covers over 11,000 square miles, with ever-expanding field boundaries, and we continually pursue opportunities to increase our working interest and acreage position. We are accelerating Spraberry field development in 2006, almost doubling the level of activity, with plans to drill approximately 350 wells. We also see opportunities to target deeper zones, and a portion of these wells will test that potential.

In the Texas Panhandle and extending north into Kansas, Pioneer's long-lived Hugoton and West Panhandle gas fields also contribute to our solid North American foundation with dependable production and cash flow.

In South Texas, we are expanding our Pawnee resource play concept along the Edwards Reef trend with very promising results. We have been the most active driller in this area for several years and have established a large and growing acreage position along the trend. We've added significant production and reserves and gained critical knowledge and experience, cutting the time needed to drill a well by half over the last five years. During 2006, we plan to drill 30 to 40 wells to develop reserves and further define this opportunity.

Big Bend National Park, shown here, is approximately 200 miles south of Pioneer's operations in West Texas.

Pioneer has an active drilling program underway in the Edwards Reef trend in South Texas. In the heart of the 250-mile trend, the Company is developing its Pawnee field in which the estimate of gross ultimate recoverable gas reserves has grown every year over the last 10 years and more than doubled during that time. To expand on its Pawnee success, Pioneer has been actively acquiring acreage covering a number of analogous prospects. Early test results from two discoveries drilled in late 2005 and early 2006 are very encouraging.

The Rocky Mountains are home to Pioneer's CBM gas operations in the Raton Basin and promising pilot programs testing the CBM resource potential of three other basins in northern Colorado and Utah.

In the Raton Basin, Pioneer utilizes an integrated services model and owns and operates most of the equipment used in the field, including the coiled-tubing drilling rig shown here. This model allows the Company to control costs and the availability of services, gain drilling and completions efficiencies and improve quality. Pioneer owns one other drilling rig, six workover rigs, four fracture stimulation fleets and other service and maintenance equipment and employs the crews responsible for operating the equipment.

Pioneer entered the Rockies in 2004 with its merger with Evergreen Resources, becoming the largest operator in the long-lived Raton Basin CBM play and gaining prospective acreage in other Rockies basins. We plan to drill 330 Raton wells duing 2006 and have a large inventory of future drilling locations providing growth opportunities for years to come. By owning much of the equipment required to drill and operate wells in this resource play, Pioneer not only gains 100% access to the equipment, but is also able to more actively manage its costs and has set the industry standard for efficient operations.

We are leveraging our Raton expertise to develop other emerging CBM projects in the Rockies and southern Canada. Northwest of the Raton Basin, on both sides of the Colorado/Utah border, Pioneer is testing the resource potential of horizontal CBM wells in the Uinta, Piceance and Sand Wash basins. We have over 150,000 net acres with CBM potential in these basins, 27 producing wells and 35 wells that are being tested or awaiting completion or pipeline access. Based on these encouraging results, Pioneer plans to drill 50 CBM wells in these basins during 2006 and believes that success with these wells could establish the potential for more than 1,500 future drilling locations.

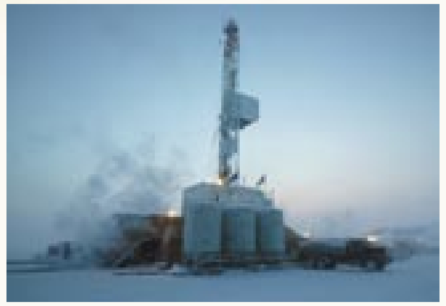
Pioneer's activities in Canada are centered in two areas, the Chinchaga field which straddles the border in northern British Columbia and Alberta and the Horseshoe Canyon and Mannville coal beds in south central Alberta. While our current Canadian production and reserves are a relatively small percentage of the total company, these three resources have the potential to significantly increase our Canadian gas reserves and double our net daily gas production.

Canada's rich gas resources offer significant potential for Pioneer to steadily increase production and reserves from both conventional and unconventional fields.

Our Chinchaga field has been producing and expanding since 1994, and during 2006, we plan to duplicate our 2005 program and drill approximately 60 wells. With 150 additional well locations and sufficient infrastructure in place, we expect to continue to add new production from the field over the next few years.

In south central Alberta, Pioneer has a very active drilling campaign underway in the Horseshoe Canyon CBM play, having drilled 157 wells during the second half of 2005 and planning to drill approximately 200 wells during 2006. Mannville coal beds are also widely distributed in this area and commercially producing from nearby acreage. During 2006, Pioneer will initiate three pilot programs and drill eight horizontal wells to test the CBM potential of the Mannville formation where the Company holds 74,500 acres.

The Horseshoe Canyon CBM field was discovered in 2000 and has produced approximately 126 billion cubic feet of gas to date. Pioneer entered the field in 2004 through its merger with Evergreen Resources and has since added to its acreage position. Wells generally require less than 24 hours to drill and are fracture stimulated using nitrogen. The Company expects to add two rigs to its drilling program during the first half of 2006 and drill 200 wells by year–end.



To effectively explore for and develop new fields in Alaska, Pioneer is tackling complex projects and field development with an emphasis on lowering costs and maximizing recoverable reserves. Pioneer is utilizing a new type of rig specifically designed to withstand the arctic conditions of the North Slope while being light enough to reduce the size and construction costs of the ice roads required for moving equipment on the North Slope. The rig, Arctic Fox #1, can be transported with fewer than 35 truck loads while other rigs require approximately 120 loads.

We entered Alaska in 2002, recognizing the opportunity to bring an independent's mindset of streamlining processes and reducing costs to a landscape previously dominated by major oil companies where medium-sized prospects had been left untapped. That year we drilled three appraisal wells in the Oooguruk field during an abbreviated winter season. Earlier this year, we approved Oooguruk as our first field development project in Alaska. We are already busy building ice roads and a gravel island in preparation for development drilling beginning in 2007 and first oil production in 2008.

We have a similar opportunity under evaluation in southern Alaska in the Cook Inlet. During 2005, we took a working interest in the Cosmopolitan unit and completed a 3-D seismic survey over a field that had been discovered by previous drilling. We hope to complete our evaluation and make a decision on assuming operatorship of the unit, which is approximately two miles offshore and 65 miles to the nearest refinery, by mid-2006.

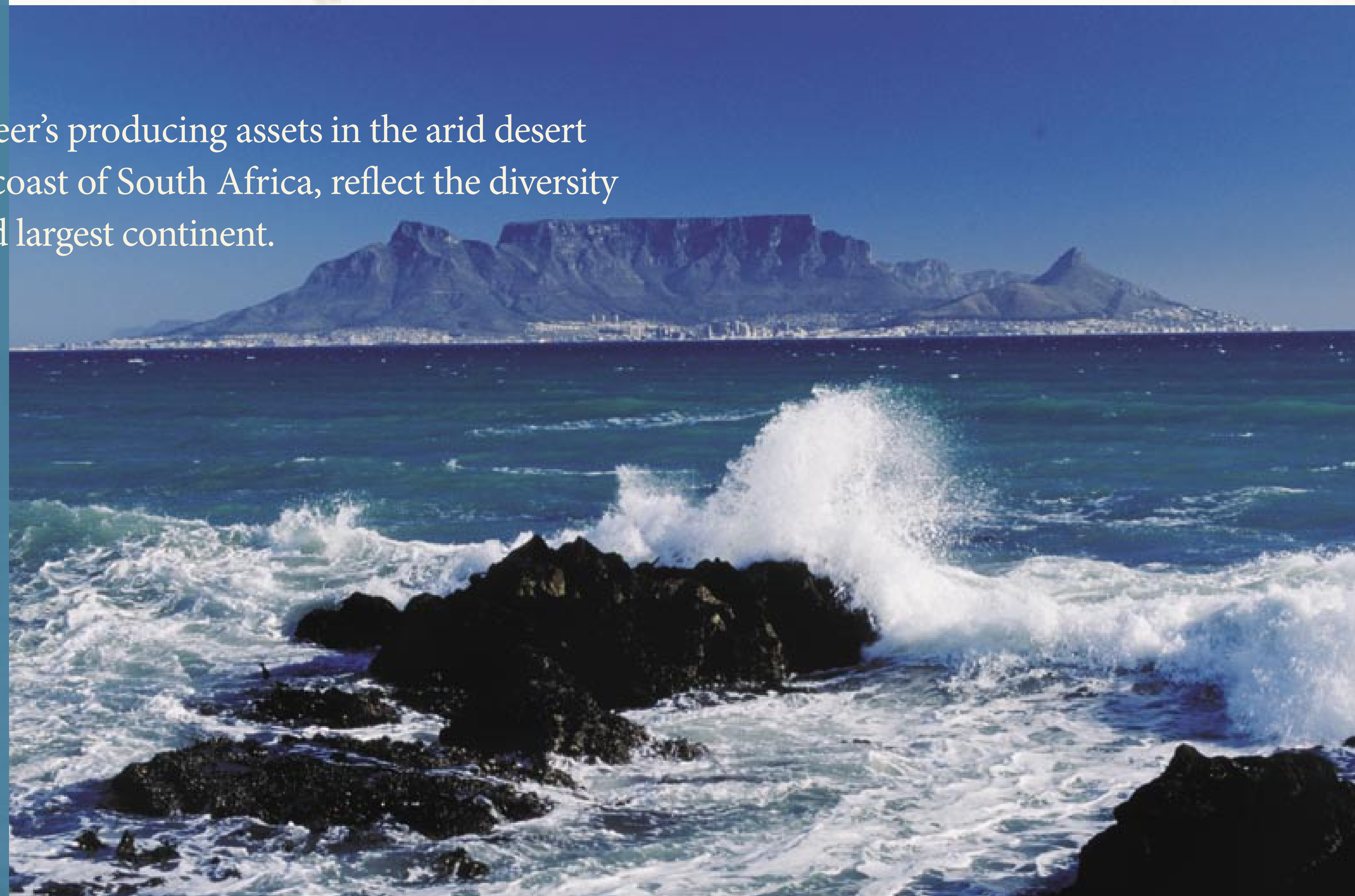
Alaska has long been known for its rich oil and gas resources, and when legislative changes opened access to new entrants, Pioneer became one of the first independents to operate on the North Slope.

On the central North Slope, we have also gained acreage near existing field infrastructure where we plan to drill two additional exploration wells in 2006. To drill these and other prospects, Pioneer entered a multi-year drilling contract for a new lightweight, highly mobile rig that allows for more efficient operations during the short winter drilling season.

Pioneer's goal to enter North Africa was realized when, in 2001, we acquired interests in several blocks in the prolific Ghadames Basin in Tunisia. Early drilling success resulted in the discovery of the Adam field, which is currently producing approximately 17,000 gross barrels of oil per day from the eight wells drilled with 100% success. We have recently expanded our position in Tunisia and will assume operatorship of an adjacent block where we plan to acquire 3-D seismic and initiate our drilling program this summer. We also see potential to extend our North African holdings into neighboring Libya and Algeria.

Pioneer is promoting advanced visualization and illumination techniques to enhance subsurface seismic interpretation, overcoming inherent limitations associated with imaging below the North African desert terrain. Pioneer has built a large acreage position in Tunisia, recently acquiring the remaining equity interest and assuming operatorship of the Jenein Nord block, which is west of the Adam Concession where Pioneer and its partner have produced over 10 million barrels of oil since initiating production in May 2003. During 2006, Pioneer plans to acquire additional 3-D seismic data on acreage in the Adam Concession and the Jenein Nord block and expand its drilling program.

Africa is a land of contrasts, and Pioneer's producing assets in the arid desert of North Africa and off the beautiful coast of South Africa, reflect the diversity one would expect of the world's second largest continent.



On the opposite end of the continent, approximately 5,000 miles away, Pioneer has partnered with PetroSA, the national oil company of South Africa, in commercializing oil from the offshore Sable field which began producing in 2003. During 2005, the partners approved a project to jointly develop several South Coast gas discoveries to provide supply to the existing gas-to-liquids plant at Mossel Bay beginning in the second half of 2007.

Pioneer's interest in Africa also extends west to the deep waters offshore Nigeria and Equatorial Guinea, an area known for large oil discoveries. The higher-potential reward of large prospects does come with higher risks, and we plan to mitigate our risk by participating in multiple prospects, drilling two wells per year in 2006 and 2007 with the hope of utilizing our deepwater expertise to develop a discovery.

Table Mountain, shown here, towers above the city of Cape Town where we maintain our South African office.

Corporate Responsibility

Pioneer understands that sustainable financial success relies on the safety of our employees and our respect for the environment and the communities in which we operate. We also know that solid corporate governance and compliance policies and procedures are critical to protecting the interests of all stakeholders.

The Environment and Safety

Pioneer's operations are conducted in a manner that supports environmentally appropriate and socially beneficial strategies to help provide the energy resources that our world needs.

Our efforts to safeguard the environment have been recognized by the Interstate Oil and Gas Compact Commission's stewardship award program. Through this program the commission recognizes exemplary efforts in environmental stewardship, reserved for the companies that have gone above and beyond the basic mandates of law to protect the environment. Pioneer has also been named STAR Gas Processing Partner of the Year by the U.S. Environmental Protection Agency, who also conducted a case study of Pioneer's program as an example for others to follow.

Concern for the environment, health and safety are a part of our employees' daily activities. For example, employees in Canada are completing the ninth year of a wildlife field study that has been widely distributed in the Provincial Governments of Alberta and British Columbia. They are working with wildlife agencies to study the stress levels of caribou, moose and wolves in an effort to minimize the industry's impact on wildlife in Pioneer's areas of operation. In Colorado, Pioneer is working with the Colorado Department of Wildlife and sponsoring a similar study of the local elk population.

Pioneer is also committed to the health and safety of our employees and their surroundings and demonstrates this commitment in all relevant business decisions. Pioneer expects employees to proactively participate in striving to prevent accidents, injuries and occupational illnesses. To further emphasize the importance of these considerations, compliance with our policies on protecting the environment and our people's safety is a part of every employee's annual performance review.

Community

Pioneer's commitment extends beyond our concern for employees to a desire to improve the communities where we operate and where our employees live and work. Our employees, supported by matching contributions from Pioneer, have given generously to the United Way and other charitable organizations.

Employees across North America also joined Pioneer in supporting the disaster relief efforts following Hurricanes Katrina and Rita. In addition to contributing to the efforts of the American Red Cross and the Salvation Army, a foundation was established to assist current and former employees who were victims of the 2005 hurricanes as they began to rebuild their homes and their lives.

Employees have also contributed their time and energy, combined with Pioneer's financial support, to benefit numerous local organizations, helping build a house for a needy family in Anchorage through Habitat for Humanity and in support of education, youth development, the arts, and the health and welfare of others across all areas of operation.

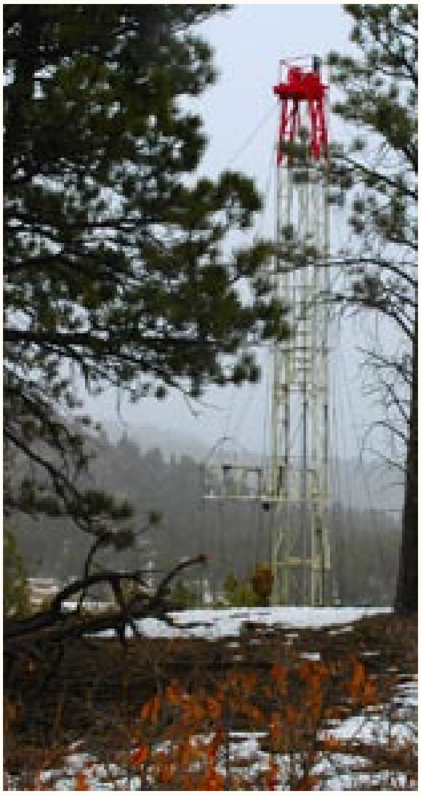
Recognizing the burden of rising energy costs, we have established a program to assist needy senior citizens in Las Animas County, Colorado with their winter heating bills and also continued our support for the statewide energy assistance program for low-income families.

Pioneer's mission, providing energy that supports the health and well-being of our world, is itself a service to our communities, and by doing even more, we demonstrate our commitment to improving the lives of others.

Guiding Principles

Our strong culture of ethics and governance is at the core of our business, and we strive for continual enhancement. Through our Code of Business Conduct, all directors, officers and employees are held to high ethical standards.

We are governed by principles that ensure that we are not just compliant with rules and regulations, but that we strive for leadership within our industry. All of our Board's committees are made up of independent Directors actively involved in strategic oversight and committed to ensuring strong governance and corporate responsibility.



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Pioneer Natural Resources Company 2005 10-K

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, 2005

or

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

For the transition period from to

Commission File Number: 1-13245

Pioneer Natural Resources Company

(Exact name of registrant as specified in its charter)

Delaware	**75-2702753**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5205 N. O'Connor Blvd., Suite 900, Irving, Texas	**75039**
(Address of principal executive offices)	*(Zip Code)*

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 ☑ No ☐

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter	**$5,903,355,355**
Number of shares of Common Stock outstanding as of February 15, 2006	**128,642,016**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held during May 2006 — Referenced in Part III of this report.

TABLE OF CONTENTS

Cautionary Statement Concerning Forward-Looking Statements

Parts I and II of this annual report on Form 10-K (the "Report") contain forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company ("Pioneer" or the "Company") or its management are intended to identify forward-looking statements. The forward-looking statements are based on our current expectations, assumptions, estimates and projections about the Company and the industry in which we operate. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations", "Item 1A. Risk Factors" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a description of various factors that could materially affect the ability of Pioneer to achieve the anticipated results described in the forward-looking statements. The Company undertakes no duty to publicly update these statements except as required by law.

Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

- *"Bbl"* means a standard barrel containing 42 United States gallons.
- *"Bcf"* means one billion cubic feet.
- *"BOE"* means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or natural gas liquid.
- *"BOEPD"* means BOE per day.
- *"Btu"* means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- *"field fuel"* means gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.
- *"GAAP"* means accounting principles that are generally accepted in the United States of America.
- *"LIBOR"* means London Interbank Offered Rate, which is a market rate of interest.
- *"MBbl"* means one thousand Bbls.
- *"MBOE"* means one thousand BOEs.
- *"Mcf"* means one thousand cubic feet and is a measure of natural gas volume.
- *"MMBbl"* means one million Bbls.
- *"MMBOE"* means one million BOEs.
- *"MMBtu"* means one million Btus.
- *"MMcf"* means one million cubic feet.
- *"NGL"* means natural gas liquid.
- *"NYMEX"* means the New York Mercantile Exchange.
- *"NYSE"* means the New York Stock Exchange.
- *"Pioneer"* or the *"Company"* means Pioneer Natural Resources Company and its subsidiaries.
- *"proved reserves"* mean the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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

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

  (iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (C) crude oil, natural gas and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.
- *"SEC"* means the United States Securities and Exchange Commission.
- *"Standardized Measure"* means the after-tax present value of estimated future net revenues of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs in effect at the specified date and a 10 percent discount rate.
- With respect to information on the working interest in wells, drilling locations and acreage, *"net"* wells, drilling locations and acres are determined by multiplying *"gross"* wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
- Unless otherwise indicated, all currency amounts are expressed in U.S. dollars.

PART I

ITEM 1. BUSINESS

General

Pioneer is a Delaware corporation whose common stock is listed and traded on the NYSE. The Company is a large independent oil and gas exploration and production company with operations in the United States, Argentina, Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia.

The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 900, Irving, Texas 75039. The Company's telephone number is (972) 444-9001. The Company maintains other offices in Anchorage, Alaska; Denver, Colorado; Midland, Texas; Buenos Aires, Argentina; Calgary, Canada; London, England; Lagos, Nigeria; Capetown, South Africa and Tunis, Tunisia. At December 31, 2005, the Company had 1,694 employees, 912 of whom were employed in field and plant operations.

Available Information

Pioneer files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC. The public can obtain any documents that Pioneer files with the SEC at http://www.sec.gov.

The Company also makes available free of charge on or through its internet website (www.pxd.com) its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

In 2005, the Company submitted the annual certification of its Chief Executive Officer regarding the Company's compliance with the NYSE's corporate governance listing standards, pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

Evergreen Merger

On September 28, 2004, Pioneer completed a merger with Evergreen Resources, Inc. ("Evergreen"). Pioneer acquired the common stock of Evergreen for a total purchase price of approximately $1.8 billion, which was comprised of cash and Pioneer common stock. Evergreen was a publicly-traded independent oil and gas company primarily engaged in the production, development, exploration and acquisition of North American unconventional natural gas. Evergreen's operations were principally focused on developing and expanding its coal bed methane ("CBM") field located in the Raton Basin in southern Colorado. Evergreen also had operations in the Piceance Basin in western Colorado, the Uinta Basin in eastern Utah and the Western Canada Sedimentary Basin. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding the Evergreen merger.

Mission and Strategies

The Company's mission is to enhance shareholder investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. These strategies are anchored by the Company's long-lived Spraberry oil field and Hugoton, Raton and West Panhandle gas fields' reserves and production which have an estimated remaining productive life in excess of 40 years. Underlying these fields are approximately 78 percent of the Company's proved oil and gas reserves as of December 31, 2005.

Recent strategic initiatives. During September 2005, the Company announced that its board of directors (the "Board") approved significant strategic initiatives intended to enhance shareholder value and investment returns. Together with other important initiatives, the Board approved:

- A $1 billion share repurchase program, $650 million of which was immediately initiated and substantially completed during 2005 and $350 million of which is subject to the completion of the planned deepwater Gulf of Mexico and Argentina divestitures discussed below.
- A plan to divest the Company's assets in the Tierra del Fuego area in southern Argentina. The plan was later broadened to include entertaining offers for a complete sale of all of the Company's Argentine assets. During January 2006, Pioneer entered into an agreement to sell its assets in Argentina for $675 million.
- A plan to divest the Company's assets in the deepwater Gulf of Mexico. Bids to purchase the properties were received in January 2006 and the Company is currently engaged in negotiations for the sale of these assets. No assurance can be given that a sale can be completed on terms acceptable to the Company.

The implementation of the Board's strategic initiatives is allowing Pioneer to (i) allocate and focus its investment capital more heavily towards predictable oil and gas basins in North America that have delivered relatively strong and consistent growth and (ii) lower its risk profile by expanding North American unconventional resource investments while reducing higher-risk exploration expenditures.

The divestiture of the Company's Argentine oil and gas assets will allow the Company to leverage the current commodity price environment to monetize and exit operations in an area that has become characterized by lower operating margins, government-controlled pricing and modest production growth opportunities. The divestiture of the Company's deepwater Gulf of Mexico assets, if successful, will also allow the Company to monetize and exit operations in an area that is characterized by escalating drilling and operating costs and relatively high exploration risk and production volatility.

During 2006, the Company plans to: (i) selectively explore for and develop proved reserve discoveries in areas that it believes will offer superior reserve growth and profitability potential; (ii) evaluate opportunities to acquire oil and gas properties that will complement the Company's exploration and development drilling activities; (iii) invest in the personnel and technology necessary to maximize the Company's exploration and development successes; and (iv) 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 production 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 by employing experienced management and staff that will lead the Company to prudent capital investment decisions, technological innovation and price and cost management.

Petroleum industry. The petroleum industry has generally been characterized by rising oil, NGL and gas commodity prices during 2005 and recent years. During 2005, the Company has also been affected by increasing costs, particularly higher drilling and well servicing rig rates and drilling supplies. During recent years, world oil prices have increased in response to increases in demand in Asian economies, hurricane activity in the Gulf of Mexico and supply disruptions and threatened disruptions in the Middle East and Venezuela. North American gas prices have improved as overall demand fundamentals have strengthened while supply uncertainties still remain. Significant factors that will impact 2006 commodity prices include developments in the issues currently impacting Iraq and Iran and the Middle East in general; the extent to which members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations are able to continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals. To mitigate the impact of commodity price volatility on the Company's net asset value, Pioneer utilizes commodity hedge contracts. See

"Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the impact to oil and gas revenues during 2005, 2004 and 2003 from the Company's hedging activities and the Company's open hedge positions at December 31, 2005.

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, the Raton gas field located in southern Colorado and the West Panhandle gas field located in the Texas Panhandle. Complementing these areas, the Company has exploration and development opportunities and/or oil and gas production activities in the Gulf of Mexico, the onshore Gulf Coast area and in Alaska, and internationally in Argentina, Canada, Equatorial Guinea, Nigeria, 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, Colorado, Louisiana, Utah and the Gulf of Mexico, and internationally in Argentina, Canada, South Africa and Tunisia.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGLs and gas through development drilling, production enhancement activities and acquisitions of producing properties while minimizing the controllable costs associated with the production activities. During the year ended December 31, 2005, the Company's average daily production, on a BOE basis, decreased as a result of (i) production curtailments in the Gulf of Mexico resulting from 2004 and 2005 hurricane damages, (ii) production curtailment in the United States Mid-Continent area during mid-May through mid-July due to the fire at the Company's Fain gas plant and (iii) full production of recoverable reserves from the Harrier field in the deepwater Gulf of Mexico during the third quarter of 2005. Partially offsetting these decreases in production volumes were (i) a full year of gas production from the properties acquired in the Evergreen merger, (ii) increased production from the Company's Devils Tower oil field in the deepwater Gulf of Mexico despite hurricane disruptions, (iii) increased production from the Company's Raptor and Tomahawk gas fields in the deepwater Gulf of Mexico and (iv) increased production from the Company's Argentine and Canadian subsidiaries, primarily in response to increased development drilling. Production, price and cost information with respect to the Company's properties for 2005, 2004 and 2003 is set forth under "Item 2. Properties — Selected Oil and Gas Information — Production, Price and Cost Data".

The aforementioned divestitures of the Argentine and deepwater Gulf of Mexico assets, if successfully completed, will significantly reduce the Company's 2006 production volumes.

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 three years ended December 31, 2005, the Company drilled 1,626 gross (1,484 net) wells, 91 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $2.1 billion.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2005 include proved undeveloped reserves and proved developed reserves that are behind pipe of 196 MMBOE of oil and NGLs and 1,233 Bcf of gas. Development of these proved reserves will require future capital expenditures. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company's expected operating cash flows and the Company's financial condition. The Company believes that its current portfolio of proved reserves and unproved prospects provides attractive development and exploration opportunities for at least the next three to five years.

Exploratory activities. The Company has devoted significant efforts and resources to hiring and developing a highly skilled exploration staff as well as acquiring a portfolio of exploration opportunities. During September 2005, the Company announced that the Board approved strategic initiatives to implement a plan to exit exploration in the deepwater Gulf of Mexico and the Tierra del Fuego area in Argentina and to focus its exploration efforts in onshore North America, Alaska and Africa. Associated therewith, and pending approval of a 2006 capital spending budget, the Company plans to reduce its 2006 exploration budget to less than 20 percent of the total 2006 capital budget. The Company anticipates that its 2006 exploration efforts will be concentrated domestically in the onshore Gulf Coast area, the Rocky Mountain area and Alaska, and internationally in Africa and Canada. 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 1A. Risk Factors — Drilling activities" below.

Acquisition activities. The Company regularly seeks to acquire properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. In addition, the Company pursues strategic acquisitions that will allow the Company to expand into new geographical areas that feature producing properties and provide exploration/exploitation opportunities. During 2005, 2004 and 2003, the Company invested $269.7 million, $2.6 billion (including $2.5 billion associated with the Evergreen merger) and $151.0 million, respectively, of acquisition capital to purchase proved oil and gas properties, including additional interests in its existing assets, and to acquire new prospects for future exploitation and exploration activities. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Company's acquisitions during 2005, 2004 and 2003.

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. The success of any acquisition will depend on a number of factors. See "Item 1A. Risk Factors-Acquisitions".

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While the Company generally does not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering the Company's objective of increasing financial flexibility through reduced debt levels.

During September 2005, the Company announced that the Board had approved a series of strategic initiatives, including a plan to divest the Company's nonoperated Tierra del Fuego interests in southern Argentina and the Company's deepwater Gulf of Mexico portfolio. During the Argentine sale process, the Company had indications from several potential buyers that they could enhance their value for a transaction in Argentina if it included all of the Company's properties. Consequently, the Company expressed its willingness to entertain offers for a complete exit from Argentina. During January 2006, the Company announced signing an agreement with Apache Corporation to sell all of its assets in Argentina for $675 million, subject to normal closing adjustments. The sale to Apache Corporation is expected to close during the latter part of the first quarter or in early April of 2006.

The deepwater Gulf of Mexico bid process has been completed and the Company is currently engaged in negotiations for the sale of the properties. No assurance can be given that a sale can be completed on terms acceptable to the Company.

During 2005, the Company's material divestitures consisted of (i) the sale of three volumetric production payments ("VPPs") in the Spraberry and Hugoton fields for net proceeds of approximately $892.6 million, (ii) the sale of all of its interests in the Martin Creek, Conroy Black and Lookout Butte oil and gas properties in Canada for net proceeds of $197.2 million, which resulted in a gain of $138.3 million that is included in the Company's discontinued operations; (iii) the sale of all of its interests in certain oil and gas properties on the shelf of the Gulf of Mexico for net proceeds of $59.1 million, which resulted in a gain of $27.7 million that is included in the Company's discontinued operations; and (iv) the sale of all of its shares in a subsidiary that owns the interest in the Olowi block in Gabon for net proceeds of $47.9 million, which resulted in a gain of $47.5 million that is included in the Company's 2005 income from continuing operations. The net cash proceeds were primarily used to fund additions to oil and gas properties or to reduce the Company's outstanding indebtedness. See Notes N and T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures and VPPs entered into by the Company during 2005.

The Company anticipates that it will continue to sell nonstrategic properties or other assets from time to time to increase capital resources available for other activities, to achieve operating and administrative efficiencies and to improve profitability.

Operations by Geographic Area

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

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as the index or spot price for gas or the posted price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply conditions. In Argentina, the Company receives significantly lower prices for its production as a result of the Argentine government's imposed price limitations. See "Qualitative Disclosures" in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of Argentine foreign currency, operations and price risk.

Significant purchasers. During 2005, the Company's primary purchasers of oil, NGLs and gas were Williams Power Company, Inc. (nine percent), Occidental Energy Marketing, Inc. (nine percent), ConocoPhillips (seven percent), Plains Marketing LP (seven percent) and Tenaska Marketing (six percent). The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on its ability to sell its oil, NGL and gas production.

Hedging activities. The Company utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's hedging activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact on oil and gas revenues during 2005, 2004 and 2003 from the Company's commodity hedging activities and the Company's open commodity hedge positions at December 31, 2005.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive. A large number of companies, including major integrated and other independent companies, and individuals engage in the exploration for and development of oil and gas properties, and there is a high degree of competition for oil and gas properties suitable for development or exploration. Acquisitions of oil and gas properties have been an important element of the Company's growth. The Company intends to continue to acquire oil and gas properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, evaluate and purchase such properties and the financial resources necessary to acquire and develop the properties. Higher recent commodity prices have increased the cost of properties available for acquisition. Many of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company.

Markets. The Company's ability to produce and market oil, NGLs and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect these commodity prices or the degree to which these prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production.

Governmental regulations. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the SEC and the NYSE. This regulatory oversight imposes on the Company the responsibility for establishing and maintaining disclosure controls and procedures that will ensure that material information relating to the Company and its consolidated subsidiaries is made known to the Company's management and that the financial statements and other financial information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading.

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 also generally impose a production or severance tax with respect to the 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 the United States 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 U.S. federal, state and local, as well as foreign, laws and regulations governing the discharge of substances into the environment or otherwise 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. The Company's inability to obtain these permits in a timely manner or at all could cause delays or otherwise negatively impact the Company's ability to implement its business plans. Failure to comply with these environmental laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that limit or prevent operations. Although the Company believes that compliance with U.S. and foreign environmental laws and regulations will not have a material adverse effect on its future 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 will not be incurred or that curtailment in production or processing might not arise as a result of such compliance. 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.

In the U.S., 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, strict 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 in the U.S., including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous 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 in the U.S. that for many years have been used for the exploration and production of oil and gas reserves. 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 hydrocarbons or wastes have been taken for recycling or 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 hydrocarbons or 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 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 of the U.S. 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 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 pipes and production equipment. Certain state regulations 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 the regulation of NORM has minimal effect on its operations because the Company generates only small quantities of NORM on an annual basis.

The Company's field operations in the U.S. involve the use of gas-fired compressors, which are subject to the federal Clean Air Act and analogous state laws governing the control and permitting of air emissions. The Company believes that it is in substantial compliance with applicable permitting and control technology requirements of such laws and regulations; however, in the future, additional facilities could become subject to additional permitting, monitoring and pollution control requirements as compressor facilities are expanded.

The Company's operations outside of the U.S. are potentially subject to similar foreign governmental controls relating to protection of the environment. The Company believes that compliance with existing requirements of these foreign governmental bodies has not had a material adverse effect on the Company's operations.

ITEM 1A. RISK FACTORS

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities. Other risks are described in "Item 1. Business — Competition, Markets and Regulations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". If any of these risks actually occur, they could materially harm the Company's business, financial condition or results of operations and impair Pioneer's ability to implement business plans or complete development projects as scheduled. In that case, the market price of the Company's common stock could decline.

Commodity prices. The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on oil and gas prices, which are affected by numerous factors beyond the Company's control. Historically, oil and gas prices 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 goodwill and the recognition of deferred tax asset valuation allowances or an increase to the Company's deferred tax asset valuation allowances, depending on the Company's tax attributes in each country in which it has activities. Pioneer makes price assumptions that are used for planning purposes, and a significant portion of the Company's operating expenses, including rent, salaries and noncancellable capital commitments, is largely fixed in nature. Accordingly, if commodity prices are below expectations, Pioneer's financial results are likely to be adversely and disproportionately affected because these expenses are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

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. The Company expects that it will continue to experience exploration and abandonment expense in 2006 even though less than 20 percent of the Company's 2006 capital budget is devoted to higher-risk exploratory projects. Increased levels of drilling activity in the oil and gas industry in recent periods have led to reduced availability, extended delivery times and increased costs of some drilling equipment, materials and supplies. The Company expects that these trends will continue in the foreseeable future and, if so, will impact the Company's profitability, cash flow and ability to complete development projects as scheduled.

Unproved properties. At December 31, 2005, the Company carried unproved property costs of $313.9 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods.

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 reserves on a profitable basis. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the costs to develop the reserves, the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and the assessment of 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 nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of nonstrategic assets, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to the Company.

Operation of gas processing plants. As of December 31, 2005, the Company owned interests in 12 gas processing plants and three treating facilities. The Company operates eight of the plants and all three treating facilities. There are significant risks associated with the operation of gas processing plants. For example, in May 2005, the Company's Fain gas plant was shut in for two months due to a mechanical failure that resulted in a fire. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a gas processing plant or facility could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source.

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, adverse weather effects 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. Increased hurricane activity over the past two years has resulted in production curtailments and physical damage to the Company's Gulf of Mexico 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 and deductibles associated with obtaining such insurance.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of United States federal, state and local, as well as foreign laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to administrative, civil, or criminal penalties, remedial cleanups, and natural resource damages or other liabilities and compliance may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business — Competition, Markets and Regulations — Environmental and health controls" above for additional discussion related to environmental risks.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that future environmental laws will not result in a curtailment of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or adversely affect the Company's future operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Debt restrictions and availability. The Company is a borrower under fixed rate senior notes and a variable rate credit facility. The terms of the Company's borrowings under the senior notes and the credit facility specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices and interest rates. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt as of December 31, 2005 and the terms associated therewith.

The Company's ability to obtain additional financing is also impacted by the Company's debt credit ratings and competition for available debt financing. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the Company's debt credit ratings.

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 Regulations" above for additional discussion regarding competition.

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 Regulations" above for additional discussion regarding government regulation.

International operations. At December 31, 2005, approximately 14 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (ten percent in Argentina, two percent in Canada and two percent in 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 import-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 may adversely affect the Company's future results of operations and financial condition. See "Critical Accounting Estimates" included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", "Qualitative Disclosures" in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information specific to Argentina's economic and political situation and other risks associated with the Company's international operations. The aforementioned planned sale of Argentine assets, if completed, will significantly reduce the Company's international operations.

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.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas,
- the quality and quantity of available data,
- the interpretation of that data,
- the assumed effects of regulations by governmental agencies,
- assumptions concerning future oil and gas prices and
- assumptions concerning future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs.

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

- the quantities of oil and gas that are ultimately recovered,
- the production and operating costs incurred,
- the amount and timing of future development expenditures and
- future oil and gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production,
- increases or decreases in the supply or demand of oil and gas and
- changes in governmental regulations or taxation.

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

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of oil and gas prices, as well as operating and development costs, prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received. Therefore, the estimates of discounted future net cash flows or Standardized Measure in this Report should not be construed as accurate estimates of the current market value of the Company's proved reserves.

Stock repurchases. During 2005, the Company repurchased 20 million shares of its common stock, and announced its intention to repurchase up to an additional $350 million of its common stock, subject to completion of the planned divestiture of its deepwater Gulf of Mexico and Argentine assets. The Board sets limits on the price per share at which Pioneer's common stock can be repurchased, and the Company will not be permitted to repurchase its stock during certain periods because of scheduled and unscheduled trading blackouts. Additionally, business conditions and availability of capital may dictate that repurchases be suspended or cancelled. As a result, there can be no assurance that additional repurchases will be commenced and, if so, that they will be completed.

Commodity hedges. To the extent that the Company engages in hedging activities to reduce commodity price risk, Pioneer may be prevented from realizing the benefits of price increases above the levels of the hedges. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2005, 2004 and 2003, which are located in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The reserve audits performed by NSAI in aggregate represented 82 percent, 88 percent and 87 percent of the Company's 2005, 2004 and 2003 proved reserves, respectively; and, 76 percent, 84 percent and 89 percent of the Company's 2005, 2004 and 2003 associated present value of proved reserves discounted at ten percent, respectively.

NSAI follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers ("SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. The SPE's definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been presented in conformity with generally accepted petroleum engineering and evaluation principles.
- The estimation of proved reserves is an imprecise science due to the many unknown geologic and reservoir factors that cannot be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by a company is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.
- The methods and procedures used by a company, and the reserve information furnished by a company, must be reviewed in sufficient detail to permit the reserve auditor, in its professional judgment, to express an opinion as to the reasonableness of the reserve information. The auditing procedures require the reserve auditor to prepare its own estimates of reserve information for the audited properties.

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

In the course of their evaluations, NSAI prepared, for all of the audited properties, their own estimates of the Company's proved reserves and present value of such reserves discounted at ten percent. NSAI's estimates of those proved reserves and present value of such reserves discounted at ten percent did not differ from the Company's estimates by more than ten percent in the aggregate. However, when compared on a field-by-field or area-by-area basis, some of the Company's estimates were greater than those of NSAI and some were less than the estimates of NSAI. When such differences do not exceed ten percent in the aggregate and NSAI is satisfied that the proved reserves and present value of such reserves discounted at ten percent are reasonable and that their audit objectives have been met, NSAI will issue a completed unqualified audit opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analyses by the Company and NSAI. At the conclusion of the audit process, it is NSAI's opinion, as set forth in its audit letters, that Pioneer's estimates of the Company's proved oil and gas reserves and associated future net revenues are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

The Company did not provide estimates of total proved oil and gas reserves during 2005, 2004 or 2003 to any federal authority or agency, other than the SEC. The Company's reserve estimates do not include any probable or possible reserves.

Proved Reserves

The Company's proved reserves totaled 986.7 MMBOE, 1.0 billion BOE and 789.1 MMBOE at December 31, 2005, 2004 and 2003, respectively, representing $7.3 billion, $6.6 billion and $4.6 billion, respectively, of Standardized Measure. The Company's proved reserves include field fuel which is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point. The following table shows the changes in the Company's proved reserve volumes by geographic area during the year ended December 31, 2005 (in MBOE):

	Production	Discoveries and Extensions	Acquisitions	Divestitures	Revisions	Total
United States	(49,210)	17,494	79,663	(37,964)	(29,049)	(19,066)
Argentina	(11,874)	7,602	—	—	(20,881)	(25,153)
Canada	(2,922)	9,840	49	(9,947)	3,082	102
Africa	(3,674)	12,109	—	—	184	8,619
Total	(67,680)	47,045	79,712	(47,911)	(46,664)	(35,498)

Production. Production volumes include (a) 2,409 MBOE of field fuel and (b) 1,188 MBOE of production associated with certain divested assets being presented as discontinued operations.

Discoveries and extensions. Discoveries and extensions are primarily the result of (a) drilling activity in the Raton Basin in the United States, Horseshoe Canyon and Chinchaga fields in Canada and the Neuquen Basin in Argentina and (b) the approval to begin development of the gas reserves, previously discovered, off the south coast of South Africa.

Acquisitions. Acquisition volumes are primarily attributable to the (a) July 2005 announced completion of the acquisition of 70 MBOE of proved reserves in the Spraberry field and Gulf Coast area and (b) other smaller acquisitions.

Divestitures. The divestitures are primarily attributable to (a) the sale of approximately 28 MMBOE of proved reserves in the Spraberry and Hugoton fields through three VPPs, (b) the sale of approximately 10 MMBOE of proved reserves in properties on the shelf of the Gulf of Mexico and East Texas and (c) the sale of approximately 10 MMBOE of proved reserves in the Martin Creek and Conroy Black areas of northeast British Columbia and the Lookout Butte area of southern Alberta.

Revisions. The overall downward revisions are primarily attributable to (a) the recent drilling results in the deep gas reserves in the Neuquen Basin of Argentina which indicated that the gas reservoirs are more complex and compartmentalized than expected, and (b) additional production decline history on producing wells and unexpected drilling results in certain areas of the field in the Raton Basin in the United States where a number of wells drilled on the northern rim of the field during the second half of 2005 encountered less CBM reservoir than expected due to nonproductive volcanic intrusions into the coal interval. The downward revisions were offset by increased commodity prices that extended the economic life on various properties.

On a BOE basis, 62 percent of the Company's total proved reserves at December 31, 2005 were proved developed reserves. Based on reserve information as of December 31, 2005, and using the Company's production information for the year then ended, the reserve-to-production ratio associated with the Company's proved reserves was 15 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily sales volumes by geographic area as of and for the year ended December 31, 2005:

	Proved Reserves as of December 31, 2005(a)				2005 Average Daily Sales Volumes(b)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (In thousands)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States	385,771	2,750,856	844,247	$6,078,764	43,345	497,068	126,191
Argentina	34,024	404,323	101,411	807,897(c)	9,693	137,032	32,531
Canada	2,423	130,514	24,175	254,067	713	36,427	6,784
Africa	6,824	60,395	16,890	156,169	10,065	—	10,065
Total	429,042	3,346,088	986,723	$7,296,897	63,816	670,527	175,571

(a) The gas reserves contain 306 MMcf of gas that will be produced and utilized as field fuel.

(b) The 2005 average daily sales volumes are from continuing operations and (i) do not include the field fuel produced, which averaged 6,599 BOEPD and (ii) were calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

(c) Assuming the Argentine export tax on oil remains in place after the expiration date of the law in February 2007 the standardized measure of discounted future cash flows for Argentina would be approximately $633 million at December 31, 2005.

The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2005:

Year Ended December 31,	Estimated Future Production (MBOE)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
			($ in thousands)		
2006	5,694	$ 204,592	$ 26,656	$ 666,238	$ (488,302)
2007	15,552	603,300	78,878	502,221	22,201
2008	19,470	740,419	101,040	375,092	264,287
2009	21,306	825,809	119,378	208,685	497,746
2010	21,652	862,436	130,472	212,670	519,294
Thereafter	287,562	13,008,489	3,408,631	729,274	8,870,584
	371,236	$16,245,045	$3,865,055	$2,694,180	$9,685,810

Description of Properties

As of December 31, 2005, the Company has production, development and/or exploration operations in the United States, Argentina, Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia.

United States

Approximately 78 percent of the Company's proved reserves at December 31, 2005 is located in the Spraberry field in the Permian Basin area, the Hugoton and West Panhandle fields of the Mid-Continent area and the Raton field in the Rocky Mountain area. These fields generate substantial operating cash flow and the Spraberry and Raton fields have a large portfolio of low risk drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally. The Company has preliminarily budgeted approximately $900 million to $1.0 billion for exploration and development drilling expenditures for 2006.

The following tables summarize the Company's development and exploration/extension drilling activities during 2005:

	Development Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Spraberry field	13	181	170	1	23
Hugoton field	1	18	18	1	—
West Panhandle field	11	42	50	3	—
Raton field	—	262	262	—	—
Other	7	38	37	2	6
Total United States	32	541	537	7	29

	Exploration/Extension Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Raton field	—	27	26	—	1
Other	9	18	14	7	6
Total United States	9	45	40	7	7

The following table summarizes by geographic area the Company's costs incurred, excluding asset retirement obligations, during 2005 and the total wells preliminarily planned to be drilled during 2006:

	Property Acquisition Costs					
	Proved	Unproved	Exploration Costs	Development Costs	Total	2006 Wells Planned
	(In thousands)					
United States:						
Permian Basin	$145,244	$ 2,520	$ 1,236	$130,308	$279,308	365
Mid-Continent	163	—	34	40,808	41,005	28
Rocky Mountain	—	20,050	13,207	132,876	166,133	379
Gulf of Mexico	—	12,374	150,305	94,552	257,231	4(a)
Onshore Gulf Coast	22,407	26,390	8,871	44,412	102,080	35
Alaska	—	(773)	44,070	5,427	48,724	3
Total United States	$167,814	$60,561	$217,723	$448,383	$894,481	814

(a) Includes two sidetrack wells proposed by the operator in the Aconcagua field and two delineation wells planned on the Clipper discovery.

Permian Basin

Spraberry field. The Spraberry field was discovered in 1949 and encompasses eight counties in West Texas. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. Recently, the Company has begun completing selected wells in the Wolfcamp formation at depths ranging from 9,300 feet to 10,300 feet with successful results. The Company believes the area offers excellent opportunities to enhance oil and gas production because of the numerous undeveloped drilling locations, many of which are reflected in the Company's proved undeveloped reserves, and the ability to contain operating expenses through economies of scale.

Mid-Continent

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's gas in the Hugoton field has an average energy content of 1,025 Btu. The Company's Hugoton properties are located on approximately 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 NGL production.

The Company's Hugoton operated wells are capable of producing approximately 74 MMcf of wet gas per day (i.e., gas production at the wellhead before processing or field fuel use 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 near allowable capacity during the year ended December 31, 2005.

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas in the West Panhandle field has an average energy content of 1,300 Btu and is produced from approximately 600 wells on more than 250,000 gross acres covering over 375 square miles. The Company controls 100 percent of the wells, production equipment, gathering system and gas processing plant for the field.

Rocky Mountains

Raton field. The Raton Basin properties are located in the southeast portion of Colorado. Exploration for CBM in the Raton Basin began in the late 1970s and continued through the late 1980s, with several companies drilling and testing more than 100 wells during this period. The absence of a pipeline to transport gas from the Raton Basin prevented full scale development until January 1995, when Colorado Interstate Gas Company completed the construction of the Picketwire lateral pipeline system. The Company's gas in the Raton Basin has an average energy content of 1,000 Btu. Since the completion of the Picketwire lateral, production has continued to grow, resulting in expansion of the system's capacity by its operator, the most recent expansion of which was in October 2005. The Company owns approximately 385,000 gross acres in the center of the Raton Basin with current production from coal seams of the Vermejo and Raton formations.

Piceance/Uinta Basins. The Piceance Basin is located in the central portion of western Colorado, and the Uinta Basin is located in the central portion of eastern Utah. The Company owns approximately 115,000 acres covering producing and prospective regions of the Piceance and Uinta Basins. Currently, production is established from various tight sandstone, coal and shale formations.

Sand Wash Basin. The Sand Wash Basin is the site of a potential CBM project located north of the Company's Piceance Basin properties. The Company holds a 50 percent operated interest in 114,000 gross acres in the Lay Creek field. In 2006, the Company plans to (i) refrac the wells drilled by the previous owner in two existing pilots, specifically targeting coal seams to reduce water handling and (ii) drill an additional two or three pilot programs to evaluate the potential of the project.

Gulf of Mexico

Gulf of Mexico area. In the Gulf of Mexico, the Company has focused on reserve and production growth by drilling its portfolio of shelf and deepwater development projects, high-impact, higher-risk shelf and deepwater exploration prospects and exploitation opportunities inherent in the properties the Company currently has producing on the shelf.

During September 2005, the Company announced its plans to pursue the divestment of its deepwater Gulf of Mexico assets to reduce the exploration risk and production volatility that have been associated with these assets. The deepwater Gulf of Mexico bid process has been completed and the Company is currently in negotiations for the sale of these assets. No assurance can be given that a sale can be completed on terms acceptable to the Company. However, if successfully completed, such a divestiture would remove the deepwater Gulf of Mexico from the Company's portfolio of oil and gas activities.

During 2005, the Company had five significant projects in the deepwater Gulf of Mexico, which are discussed below:

- *Canyon Express* — The Canyon Express project is a joint development of three deepwater Gulf of Mexico gas discoveries, including the Company's Total E&P USA-operated Aconcagua field and Marathon-operated Camden Hills fields, where the Company holds 37.5 percent and 33.3 percent working interests, respectively. The Company participated in the discovery of the Aconcagua gas field in 1999 and later added Camden Hills to its portfolio to enhance its ownership in the project. The Canyon Express project was approved for development in June 2000 and reached first production in September 2002. The existing Aconcagua and Camden Hills wells are expected to reach the end of their productive lives in early

2006; therefore, the Company now anticipates that the system will be shut in once the recoverable reserves are fully produced until a rig becomes available to drill sidetrack wells in the Aconcagua field. The Company has been advised by the operator of the Canyon Express system that sidetrack operations are planned for the Aconcagua field in late 2006.

- *Falcon Corridor* — The Falcon Corridor project started with the Company's Falcon field discovery during 2001, followed by the 2003 Harrier, Raptor and Tomahawk discoveries. The Company owns a 100 percent working interest in the Falcon Corridor discoveries and surrounding areas. First production from Falcon occurred in March 2003, followed by production from Harrier, Raptor and Tomahawk in 2004. During 2005, the Harrier, Raptor and Tomahawk fields were fully depleted.

- *Devils Tower Area* — The Dominion-operated Devils Tower development project was sanctioned in 2001 as a spar development project with the owners leasing a spar from a third party for the life of the field. The spar has slots for eight dry tree wells and up to four subsea tie-back risers and is capable of handling 60 MBbls of oil per day and 60 MMcf of gas per day. Devils Tower production operations were initiated in 2004 prior to being shut in due to Hurricane Ivan. Production was resumed in November 2004. In addition to the Devils Tower wells, three subsea tie-back wells in the Goldfinger and Triton satellite discoveries in the Devils Tower area were jointly tied back to the Devils Tower spar in November of 2005. The Company holds a 25 percent working interest in each of these projects.

- *Thunder Hawk* — The Murphy Exploration and Production Company-operated Thunder Hawk discovery in 2004 encountered in excess of 300 feet of net oil pay in two high-quality reservoir zones in Mississippi Canyon Block 734. The third appraisal well was spudded during the fourth quarter of 2005 and plans to complete the drilling of the previously spudded second well, which was temporarily suspended due to weather. These wells are expected to be completed during the first half of 2006. The Company owns a 12.5 percent working interest in this discovery.

- *Clipper* — During the fourth quarter of 2005, the Company announced a discovery on its Clipper prospect in the Green Canyon Block 299. The Company plans additional drilling during 2006 to further delineate the field. The Company operates the block with a 55 percent working interest.

Onshore Gulf Coast

South Texas. The Company has focused its drilling efforts in this area on the Pawnee field in the Edwards Reef trend in South Texas. The Edwards Reef trend is a tight gas limestone reservoir characterized by narrow bands of dry gas fields extending over 250 miles. In addition to the Pawnee field, the Company has operations in the SW Kenedy and Washburn fields of the Edwards Reef trend and a growing acreage position with over 160,000 acres acquired during the past year. Production depths in the trend range from 9,500 feet to 14,000 feet, from which over 1 trillion cubic feet of gas has been produced by the oil and gas industry. The Company drilled its first successful exploration well in the recently acquired acreage in the Edwards Reef trend in late 2005 and is currently producing approximately 1.3 MMcf of gas per day from the discovery. Pioneer's current plans include drilling at least 20 wells in the Edwards Reef trend during 2006, leveraging the Company's horizontal drilling expertise.

Northern Louisiana and Mississippi. The Company has acquired significant acreage in Northern Louisiana and Mississippi. During 2006, the Company is planning exploratory tests in the Hosston/Cotton Valley trend in Northern Louisiana and a Norphlet prospect in Mississippi.

Alaska

North Slope area. During 2002, the Company acquired a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope. Associated therewith, the Company drilled three exploratory wells during 2003 to test a possible extension of the productive sands in the Kuparuk River field in the shallow waters offshore. Although all three of the wells found the sands filled with oil, they were too thin to be considered commercial on a stand-alone basis. However, the wells also encountered thick sections of oil-bearing Jurassic-aged sands, and the first well flowed at a rate of approximately 1,300 Bbls per day ("BPD"). In January 2004, the Company farmed-into a large acreage block to the southwest of the Company's discovery. In the fourth quarter of 2004, Pioneer completed an extensive technical and economic evaluation of the resource potential within this area. As a result of this evaluation, the Company performed front-end engineering and permitting activities during 2005 to further define the scope of the project. In February 2006, the Company announced that it has approved and is commencing the development of the Oooguruk field in the project area. Following the construction of a gravel drilling and production site in 2006, installation of a subsea flowline and facilities are planned for 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit. Between 2007 and 2009, Pioneer plans to drill approximately 40 horizontal wells in the Oooguruk field. Total gross capital invested, including projected drilling and facility costs, is expected to range from $450 million to $525 million. First production from these wells is expected to begin in 2008.

During the first quarter of 2006, Pioneer anticipates drilling two exploration wells as operator, one with a 50 percent working interest in the Storms area, and a second, under a farm-in agreement with ConocoPhillips, with a 90 percent working interest on the Cronus prospect. Under another farm-in agreement with ConocoPhillips, Pioneer plans to participate with a 32.5 percent working interest in a third exploration well to be drilled on ConocoPhillips' Antigua prospect.

Cosmopolitan. During 2005, Pioneer announced that it entered into an agreement on the Cosmopolitan Unit in the Cook Inlet. Under this agreement, Pioneer earned a ten percent working interest in the unit from ConocoPhillips through a disproportionate spending arrangement for a 3-D seismic program undertaken during the fourth quarter of 2005. Pursuant to this agreement, Pioneer has the option to acquire an additional 40 percent interest in the Cosmopolitan Unit any time prior to June 1, 2006. Upon evaluation of the results of the aforementioned 3-D seismic program, Pioneer will determine whether or not to exercise this option.

International

The Company's international operations are located in the Neuquen and Austral Basins areas of Argentina, the Chinchaga and Horseshoe Canyon areas of Canada, the Sable oil field offshore South Africa and in southern Tunisia. Additionally, the Company has other development and exploration activities in the shallow waters offshore South Africa and oil development and exploration activities in Equatorial Guinea, Nigeria and Tunisia. As of December 31, 2005, approximately ten percent, two percent and two percent of the Company's proved reserves were located in Argentina, Canada and Africa, respectively.

The following tables summarize the Company's development and exploration/extension drilling activities outside the United States during 2005:

	Development Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Argentina	6	65	65	4	2
Canada	3	27	27	—	3
Total International	9	92	92	4	5

	Exploration/Extension Drilling				
	Beginning Wells in Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Argentina	8	29	19	14	4
Canada	21	182	87	7	109
Nigeria	—	1	—	1	—
South Africa	2	—	1	—	1
Tunisia	2	4	2	2	2
Total International	33	216	109	24	116

The following table summarizes by geographic area the Company's international costs incurred, excluding asset retirement obligations, during 2005 and the total wells preliminarily planned to be drilled during 2006:

	Property Acquisition Costs		Exploration Costs	Development Costs	Total	2006 Wells Planned
	Proved	Unproved				
	(In thousands)					
Argentina	$ —	$ 512	$ 36,878	$ 85,786	$123,176	—
Canada	2,593	7,344	43,437	77,962	131,336	298
Africa:						
Equatorial Guinea	—	—	3,395	—	3,395	1
Nigeria	—	30,663	34,134	—	64,797	1
South Africa	—	260	755	13,638	14,653	4
Tunisia	—	—	18,395	2,847	21,242	9
Other	—	—	6,926	292	7,218	—
Total International	$2,593	$38,779	$143,920	$180,525	$365,817	313

Argentina. 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 Dos Hermanas, the Anticlinal Campamento and the Estación Fernández 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 Loma Negra gas processing plant. The Company operates the Meseta Sirven block located in the southern part of the San Jorge basin in Santa Cruz Province, approximately 1,200 miles south of Buenos Aires. The production from this block, in which the Company has a 100 percent working interest, is primarily oil. 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 nonoperated production in Argentina is located in Tierra del Fuego, the most southern province in Argentina, 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 September 2005, the Company announced that it would pursue the sale of its nonoperated position in Tierra del Fuego. During the Tierra del Fuego sales process, several prospective buyers indicated that they could enhance their value for a transaction in Argentina if it included all of Pioneer's properties. The Company decided that if a buyer presented an attractive offer for all of the Argentine assets, that it would consider exiting Argentina. On January 17, 2006, the Company announced signing an agreement with Apache Corporation to sell all of the Company's interests in Argentina for $675 million (subject to normal closing adjustments). The transaction is expected to close during the latter part of the first quarter or in early April of 2006.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. In May 2005, the Company sold its ownership interests in the Martin Creek and Conroy Black areas of northeast British Columbia and the Lookout Butte area of southern Alberta for net proceeds of $197.2 million. The Company continues to exploit lower risk opportunities identified in the Chinchaga field core area of northeast British Columbia. The Company also initiated significant drilling, pipeline and facility activities in south-central Alberta targeting Horseshoe Canyon CBM potential on the existing land base in the greater Drumheller area.

Production from the Chinchaga area of northeast British Columbia is relatively dry gas from formation depths averaging 3,400 feet. The greater Drumheller area in south-central Alberta produces CBM gas, CBM condensate and minor oil from Cretaceous to Devonian formations at depths ranging from 400 to 6,500 feet. The Company has CBM gas production currently from the Horseshoe Canyon coal and further exploitation drilling will occur throughout the area in 2006.

Equatorial Guinea. The Company owns a 50 percent working interest in Block H offshore Equatorial Guinea. The Company has identified several prospects on the block that are being evaluated for future drilling, one of which is expected to be drilled during 2006 or 2007.

Nigeria. A partially-owned subsidiary of the Company joined Oranto Petroleum and Orandi Petroleum in an existing production sharing contract on Block 320 in deepwater Nigeria gaining exploration rights from the Nigerian National Petroleum Corporation. The subsidiary, which holds a 51 percent interest in Block 320, is owned 59 percent by the Company and 41 percent by an unaffiliated third party. The Company acquired 3-D seismic data in 2005, is currently processing the seismic and plans to drill the first well in Block 320 during 2007.

The Company owns a 26 percent working interest in Devon-operated Block 256 offshore Nigeria. The Company participated in an unsuccessful exploratory well on this block during 2005 and is participating in a second exploration well that spudded during January 2006. The timing of a third exploration well planned for the block has not been determined.

The Company had previously announced it was awarded, through a consortium, rights to acreage in Blocks 2 and 3 of the Joint Development Zone in offshore Nigeria, São Tomé and Príncipe subject to negotiating acceptable joint operating and production sharing agreements. On February 7, 2006, the Company announced that it was withdrawing from participation in both blocks.

South Africa. The Company has agreements to explore for oil and gas offshore South Africa covering over five million acres along the southern coast in water depths generally less than 650 feet. The Sable oil field began producing in August 2003 and the majority of the gas from the field has been reinjected. The Company has a 40 percent working interest in the Sable field.

In December 2005, the Company announced the final approvals with its partner in the South Coast Gas project. Pioneer has a 45 percent working interest in the project. The project will include subsea tie-back of gas from the Sable field and six additional gas accumulations to the existing production facilities on the F-A platform for transportation via existing pipelines to a gas-to-liquids ("GTL") plant. The Company has signed a contract for the sale of its share of gas and condensate to the GTL plant. Production is expected to begin during the second half of 2007 and increase to an average of approximately 100 MMcf per day of gas and 3,000 BPD of condensate over the initial phase of the project through 2012. Development drilling related to the project is expected to commence in the first quarter of 2006.

Tunisia. The Company's Tunisian permits can be separated into three categories: (i) three permits covering 2.9 million acres which the Company operates with an average 55 percent working interest, (ii) the Anadarko-operated Anaguid and Jenein Nord permits covering over 1.5 million acres in which the Company has a 45 percent working interest and (iii) the ENI-operated Adam Concession and Borj El Khadra permit covering approximately 212,000 acres and 970,000 acres, respectively, in which the Company has a 20 percent and 40 percent working interest, respectively. Production from the Adam Concession began in May 2003. All permits are onshore southern Tunisia.

In 2005, the Company conducted an extended production test of one of the two existing Anaguid Block exploration wells and drilled an offset appraisal well to the other exploration well. The results of the extended production test were unfavorable. However, the appraisal well offsetting the second discovery encountered gas and condensate in a similar horizon to the initial well. The Company is currently reviewing data from the appraisal well to determine whether development of the area is economical.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information from continuing operations for the Company as of and for each of the years ended December 31, 2005, 2004 and 2003. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The following tables set forth production, price and cost data with respect to the Company's properties for 2005, 2004 and 2003. These amounts represent the Company's historical results from continuing operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not agree to the reserve volume tables in the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" due to field fuel volumes and production from discontinued operations being included in the reserve volume tables.

The Company's lower average prices received for its Argentine commodities, as compared to the prices received in other countries, are due to price limitations imposed by the Argentine government in an effort to keep fuel and energy prices for Argentine consumers at pre-devaluation levels. These limitations have kept the prices received for oil and gas sales in Argentina well below world market levels. Beginning in 2004, the government mandated certain scheduled gas price increases through mid-2005. Those specific increases occurred as scheduled, but no specific predictions can be made about the future of oil or gas prices in Argentina. See "Qualitative Disclosures" in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of Argentine foreign currency, operations and price risk.

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2005				
	United States	Argentina	Canada	Africa	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	9,469	2,872	77	3,674	16,092
NGLs (MBbls)	6,351	666	184	—	7,201
Gas (MMcf)	181,429	50,017	13,296	—	244,742
Total (MBOE)	46,059	11,874	2,476	3,674	64,083
Average daily sales volumes:					
Oil (Bbls)	25,943	7,869	210	10,065	44,087
NGLs (Bbls)	17,402	1,824	503	—	19,729
Gas (Mcf)	497,068	137,032	36,427	—	670,527
Total (BOE)	126,191	32,531	6,784	10,065	175,571
Average prices, including hedge results:					
Oil (per Bbl)	$ 31.09	$ 36.88	$ 52.12	$ 53.00	$ 37.22
NGLs (per Bbl)	$ 31.72	$ 33.17	$ 45.79	$ —	$ 32.22
Gas (per Mcf)	$ 6.83	$ .88	$ 7.67	$ —	$ 5.66
Revenue (per BOE)	$ 37.66	$ 14.50	$ 46.18	$ 53.00	$ 34.57
Average prices, excluding hedge results:					
Oil (per Bbl)	$ 54.05	$ 36.88	$ 52.12	$ 53.00	$ 50.74
NGLs (per Bbl)	$ 31.72	$ 33.17	$ 45.79	$ —	$ 32.22
Gas (per Mcf)	$ 7.94	$ .88	$ 7.67	$ —	$ 6.49
Revenue (per BOE)	$ 46.78	$ 14.50	$ 46.18	$ 53.00	$ 41.14
Average costs (per BOE):					
Production costs:					
Lease operating	$ 4.87	$ 2.97	$ 12.94	$ 8.82	$ 5.07
Taxes:					
Ad valorem	.88	—	—	—	.63
Production	1.30	.23	—	—	.97
Workover	.36	.06	1.89	—	.34
Total	$ 7.41	$ 3.26	$ 14.83	$ 8.82	$ 7.01
Depletion expense	$ 8.71	$ 7.13	$ 12.71	$ 7.96	$ 8.53

PRODUCTION, PRICE AND COST DATA — (Continued)

	Year Ended December 31, 2004				
	United States	Argentina	Canada	Africa	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	9,041	3,123	26	4,274	16,464
NGLs (MBbls)	7,203	566	155	—	7,924
Gas (MMcf)	188,964	44,525	9,372	—	242,861
Total (MBOE)	47,738	11,110	1,743	4,274	64,865
Average daily sales volumes:					
Oil (Bbls)	24,700	8,534	72	11,676	44,982
NGLs (Bbls)	19,678	1,546	425	—	21,649
Gas (Mcf)	516,294	121,654	25,606	—	663,554
Total (BOE)	130,428	30,356	4,764	11,676	177,224
Average prices, including hedge results:					
Oil (per Bbl)	$ 29.69	$ 28.06	$ 48.37	$ 38.12	$ 31.60
NGLs (per Bbl)	$ 25.05	$ 29.91	$ 32.03	$ —	$ 25.54
Gas (per Mcf)	$ 5.14	$ .66	$ 4.72	$ —	$ 4.30
Revenue (per BOE)	$ 29.75	$ 12.07	$ 28.93	$ 38.12	$ 27.25
Average prices, excluding hedge results:					
Oil (per Bbl)	$ 39.54	$ 29.82	$ 48.37	$ 38.71	$ 37.49
NGLs (per Bbl)	$ 25.05	$ 29.91	$ 32.03	$ —	$ 25.54
Gas (per Mcf)	$ 5.71	$ .66	$ 5.37	$ —	$ 4.78
Revenue (per BOE)	$ 33.89	$ 12.56	$ 32.48	$ 38.71	$ 30.51
Average costs (per BOE):					
Production costs:					
Lease operating	$ 3.27	$ 2.75	$ 9.92	$ 7.37	$ 3.63
Taxes:					
Ad valorem	.58	—	—	—	.43
Production	.78	.23	—	—	.61
Workover	.24	.01	.87	—	.21
Total	$ 4.87	$ 2.99	$ 10.79	$ 7.37	$ 4.88
Depletion expense	$ 8.62	$ 5.56	$ 12.93	$ 11.19	$ 8.38

PRODUCTION, PRICE AND COST DATA — (Continued)

	Year Ended December 31, 2003				
	United States	Argentina	Canada	Africa	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	8,215	3,171	13	723	12,122
NGLs (MBbls)	7,411	481	173	—	8,065
Gas (MMcf)	152,560	34,357	9,774	—	196,691
Total (MBOE)	41,054	9,378	1,815	723	52,970
Average daily sales volumes:					
Oil (Bbls)	22,509	8,687	35	1,981	33,212
NGLs (Bbls)	20,306	1,318	473	—	22,097
Gas (Mcf)	417,972	94,128	26,779	—	538,879
Total (BOE)	112,477	25,693	4,971	1,981	145,122
Average prices, including hedge results:					
Oil (per Bbl)	$ 25.09	$ 25.62	$ 28.00	$29.52	$ 25.50
NGLs (per Bbl)	$ 19.03	$ 22.85	$ 24.30	$ —	$ 19.38
Gas (per Mcf)	$ 4.45	$ .56	$ 4.65	$ —	$ 3.78
Revenue (per BOE)	$ 24.99	$ 11.87	$ 27.56	$29.52	$ 22.82
Average prices, excluding hedge results:					
Oil (per Bbl)	$ 29.52	$ 26.31	$ 28.00	$30.07	$ 28.71
NGLs (per Bbl)	$ 19.03	$ 22.85	$ 24.30	$ —	$ 19.38
Gas (per Mcf)	$ 4.91	$ .56	$ 4.79	$ —	$ 4.15
Revenue (per BOE)	$ 27.59	$ 12.10	$ 28.31	$30.07	$ 24.91
Average costs (per BOE):					
Production costs:					
Lease operating	$ 3.01	$ 2.57	$ 8.83	$ 3.87	$ 3.14
Taxes:					
Ad valorem	.52	—	—	—	.41
Production	.75	.20	—	.12	.62
Workover	.16	.01	.38	—	.14
Total	$ 4.44	$ 2.78	$ 9.21	$ 3.99	$ 4.31
Depletion expense	$ 7.06	$ 4.96	$ 11.42	$10.69	$ 6.89

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, 2005, 2004 and 2003:

PRODUCTIVE WELLS(a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2005:						
United States	4,300	3,955	8,255	3,531	3,669	7,200
Argentina	821	261	1,082	684	202	886
Canada	65	675	740	30	511	541
Africa	12	—	12	4	—	4
Total	5,198	4,891	10,089	4,249	4,382	8,631
As of December 31, 2004:						
United States	3,999	3,990	7,989	3,288	3,563	6,851
Argentina	744	226	970	607	168	775
Canada	38	489	527	25	358	383
Africa	9	—	9	3	—	3
Total	4,790	4,705	9,495	3,923	4,089	8,012
As of December 31, 2003:						
United States	3,691	2,012	5,703	2,978	1,907	4,885
Argentina	669	194	863	539	141	680
Canada	4	268	272	4	210	214
Africa	7	—	7	2	—	2
Total	4,371	2,474	6,845	3,523	2,258	5,781

(a) Productive wells consist of producing wells and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. If any well in which one of the multiple completions is an oil completion, then the well is classified as an oil well. As of December 31, 2005, the Company owned interests in 214 gross wells containing multiple completions.

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2005:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty Acreage
	Gross Acres	Net Acres	Gross Acres	Net Acres	
United States:					
Onshore	1,362,840	1,186,135	2,294,074	927,528	289,517
Offshore	131,852	61,718	773,919	595,332	10,500
	1,494,692	1,247,853	3,067,993	1,522,860	300,017
Argentina	736,000	342,000	953,000	870,000	—
Canada	245,000	177,000	475,000	348,000	24,000
Africa	337,020	106,571	9,873,962	5,230,077	—
Total	2,812,712	1,873,424	14,369,955	7,970,937	324,017

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2005:

	Acres Expiring(a)	
	Gross	Net
2006(b)	3,043,642	1,627,381
2007	6,494,885	3,708,934
2008	432,316	311,651
2009	604,350	199,776
2010	125,242	91,798
Thereafter	3,669,520	2,031,397
Total	14,369,955	7,970,937

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

(b) Acres subject to expiration during 2006 include 2.6 million gross acres (1.3 million net acres) in Tunisia, 97,952 gross acres (48,976 net acres) in Equatorial Guinea and 309,069 gross acres (207,200 net acres) in North America. The Company may extend these leases prior to their expiration based upon 2006 planned activities or for other business reasons. In certain of these leases, the extension is only subject to the Company's election to extend and the fulfillment of certain capital expenditure commitments. In other cases, the extensions are subject to the consent of third parties, and no assurance can be given that the requested extensions will be granted. See "Description of Properties" above for information regarding the Company's drilling operations.

Drilling activities. The following table sets forth the number of gross and net productive and dry hole wells in which the Company had an interest that were drilled during 2005, 2004 and 2003. 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,		
	2005	2004	2003	2005	2004	2003
United States:						
Productive wells:						
Development	537	268	244	504.6	243.1	210.5
Exploratory	40	8	4	36.8	5.3	4.0
Dry holes:						
Development	7	3	6	6.8	3.0	6.0
Exploratory	7	6	6	5.3	3.0	3.6
	591	285	260	553.5	254.4	224.1
Argentina:						
Productive wells:						
Development	65	43	29	64.4	41.7	29.0
Exploratory	19	21	21	17.8	21.0	21.0
Dry holes:						
Development	4	1	2	4.0	1.0	2.0
Exploratory	14	10	9	14.0	9.5	9.0
	102	75	61	100.2	73.2	61.0
Canada:						
Productive wells:						
Development	27	3	7	26.3	3.0	7.0
Exploratory	87	27	16	71.5	24.5	14.9
Dry holes:						
Development	—	—	7	—	—	6.5
Exploratory	7	24	26	6.5	23.3	21.1
	121	54	56	104.3	50.8	49.5
Africa:						
Productive wells:						
Development	—	2	1	—	.6	.3
Exploratory	3	2	1	1.2	1.4	.4
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	3	5	4	1.2	4.4	3.5
	6	9	6	2.4	6.4	4.2
Total	820	423	383	760.4	384.8	338.8
Success ratio(a)	95%	88%	84%	95%	89%	85%

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

The following table sets forth information about the Company's wells upon which drilling was in progress as of December 31, 2005:

	Gross Wells	Net Wells
United States:		
Development	29	24.8
Exploratory	7	4.1
	36	28.9
Argentina:		
Development	2	2.0
Exploratory	4	4.0
	6	6.0
Canada:		
Development	3	2.3
Exploratory	109	98.0
	112	100.3
Africa:		
Development	—	—
Exploratory	3	1.4
	3	1.4
Total	157	136.6

ITEM 3. LEGAL PROCEEDINGS

The Company is party to the legal proceedings that are described under "Legal actions" in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The Company is also party to other proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2005.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock is listed and traded on the NYSE under the symbol "PXD". The Board declared dividends to the holders of the Company's common stock of $.22 per share and $.20 per share during each of the years ended December 31, 2005 and 2004, respectively. On February 15, 2006, the Board declared a cash dividend on common stock of $.12 per share payable on April 12, 2006 to stockholders of record on March 29, 2006.

The following table sets forth quarterly high and low prices of the Company's common stock and dividends declared per share for the years ended December 31, 2005 and 2004:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2005:			
Fourth quarter	$55.98	$45.39	$ —
Third quarter	$56.35	$39.66	$.12
Second quarter	$45.24	$36.67	$ —
First quarter	$44.82	$32.91	$.10
Year ended December 31, 2004:			
Fourth quarter	$36.85	$30.80	$ —
Third quarter	$37.50	$31.03	$.10
Second quarter	$35.18	$29.27	$ —
First quarter	$34.68	$29.60	$.10

On February 14, 2006, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $43.51 per share.

As of February 14, 2006, the Company's common stock was held by approximately 26,000 registered holders of record.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about the Company's equity compensation plans as of December 31, 2005:

	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	(b) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in First Column)
Equity compensation plans approved by security holders(c):			
Pioneer Natural Resources Company:			
Long-Term Incentive Plan	1,922,215	$20.66	8,467,964
Employee Stock Purchase Plan	—	$ —	513,406
Predecessor plans	763,183	$19.45	—
	2,685,398		8,981,370

(a) There are no outstanding warrants or equity rights awarded under the Company's equity compensation plans. The securities do not include restricted stock awarded under the Company's Long-Term Incentive Plan.

(b) The Company's Long-Term Incentive Plan provides for the issuance of a maximum number of shares of common stock equal to ten 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 number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan (the "ESPP") is based on the original authorized issuance of 750,000 shares less 236,594 cumulative shares issued through December 31, 2005. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of each of the Company's equity compensation plans.

(c) All equity compensation plans have been approved by security holders.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of treasury stock during the three months ended December 31, 2005:

Period	Total Number of Shares (or Units) Purchased(a)	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs(b)
October 2005	4,885,424	$51.18	4,884,900	
November 2005	1,359	$52.02	—	
December 2005	4,498	$51.33	—	
Total	4,891,281	$51.18	4,884,900	$9,294,950

(a) Amounts include shares withheld to fund tax withholding on employees' stock awards for which restrictions have lapsed.

(b) Excludes $350 million of planned share repurchases which are subject to the successful completion of the planned deepwater Gulf of Mexico and Argentina divestitures.

During September 2005, the Company announced that the Board had approved a new share repurchase program authorizing the purchase of up to $650 million of the Company's common stock, $640.7 million of which was completed through open market transactions by the end of 2005. The Board approved another $350 million upon the completion of the planned deepwater Gulf of Mexico and Argentina divestitures.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data as of and for each of the five years ended December 31, 2005 for the Company should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data".

	Year Ended December 31,(a)				
	2005	2004	2003	2002	2001
	(In millions, except per share data)				
Statements of Operations Data:					
Revenues and other income:					
Oil and gas	$2,215.7	$1,767.4	$1,208.6	$ 646.6	$ 780.6
Interest and other(b)	97.1	14.1	12.3	11.2	21.8
Gain on disposition of assets, net	60.5	—	1.2	4.4	7.7
	2,373.3	1,781.5	1,222.1	662.2	810.1
Costs and expenses:					
Oil and gas production	449.3	316.1	228.2	168.6	173.8
Depletion, depreciation and amortization	568.0	556.3	374.3	202.8	209.5
Impairment of long-lived assets(c)	.6	39.7	—	—	—
Exploration and abandonments	266.8	180.7	131.2	86.6	122.6
General and administrative	124.6	80.3	60.3	48.2	36.8
Accretion of discount on asset retirement obligations	7.9	8.2	5.0	—	—
Interest	127.8	103.4	91.4	95.8	131.9
Other(d)	112.8	33.7	21.3	39.6	43.4
	1,657.8	1,318.4	911.7	641.6	718.0
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	715.5	463.1	310.4	20.6	92.1
Income tax benefit (provision)(e)	(291.7)	(164.1)	67.4	(5.1)	(4.0)
Income from continuing operations before cumulative effect of change in accounting principle	423.8	299.0	377.8	15.5	88.1
Income from discontinued operations, net of tax(a)	110.8	13.9	17.4	11.2	11.9
Income before cumulative effect of change in accounting principle	534.6	312.9	395.2	26.7	100.0
Cumulative effect of change in accounting principle, net of tax(f)	—	—	15.4	—	—
Net income	$ 534.6	$ 312.9	$ 410.6	$ 26.7	$ 100.0
Income from continuing operations before cumulative effect of change in accounting principle per share:					
Basic	$ 3.09	$ 2.39	$ 3.22	$ .14	$ .89
Diluted	$ 3.02	$ 2.35	$ 3.19	$ .14	$ .88
Net income per share:					
Basic	$ 3.90	$ 2.50	$ 3.50	$ .24	$ 1.01
Diluted	$ 3.80	$ 2.46	$ 3.46	$ .23	$ 1.00
Weighted average shares outstanding:					
Basic	137.1	125.2	117.2	112.5	98.5
Diluted	141.4	127.5	118.5	114.3	99.7
Dividends declared per share	$ .22	$ .20	$ —	$ —	$ —
Balance Sheet Data (as of December 31):					
Total assets	$7,329.2	$6,733.5	$3,951.6	$3,455.1	$3,271.1
Long-term obligations and minority interests	$4,078.8	$3,357.2	$1,762.0	$1,805.6	$1,757.5
Total stockholders' equity	$2,217.1	$2,831.8	$1,759.8	$1,374.9	$1,285.4

(a) Certain amounts for periods prior to January 1, 2005 have been reclassified (i) in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144") to reflect the results of operations of certain oil and gas properties disposed of during 2005 as discontinued operations, rather than as a component of continuing operations. See Notes B and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional discussion and (ii) to conform with the current year presentation.

(b) Interest and other income in 2005 and 2004 include $73.6 million and $7.6 million, respectively, of income associated with various business interruption insurance claims. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(c) During 2005 and 2004, the Company recorded $.6 million and $39.7 million of impairment charges for its Gabonese Olowi field as development of the discovery was canceled due to significant increases in projected field development costs. See Note S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(d) Other expense for 2005, 2003, 2002 and 2001 includes losses on the early extinguishment of debt of $26.0 million, $1.5 million, $22.3 million and $3.8 million, respectively. Other expense for 2005, 2004, 2003 and 2002 includes $54.8 million, $4.3 million, $2.8 million and $1.7 million, respectively, of derivative ineffectiveness charges. Other expense for 2001 includes noncash mark-to-market charges for changes in the fair values of non-hedge financial instruments of $11.5 million. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(e) Income tax benefit for 2003 includes a $197.7 million adjustment to reduce United States deferred tax asset valuation allowances. See Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(f) Cumulative effect of change in accounting principle for 2003 relates to the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" ("SFAS 143") on January 1, 2003. See Notes B and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

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

Strategic Initiatives

During September 2005, the Company announced that the Board approved the following strategic initiatives to enhance shareholder value and investment returns:

- Approval of a $1 billion share repurchase program, $650 million of which was immediately initiated and substantially completed during 2005. The remaining $350 million is subject to the completion of the planned deepwater Gulf of Mexico and Argentine divestments discussed below.
- A plan to divest the Company's assets in the Tierra del Fuego area in southern Argentina. The plan was later broadened to include entertaining offers for a complete sale of all of the Company's Argentine assets. During January 2006, Pioneer entered into an agreement to sell its assets in Argentina for $675 million.
- A plan to divest the Company's assets in the deepwater Gulf of Mexico. Bids to purchase the properties were received in January 2006 and the Company is currently engaged in negotiations for the sale of these assets. No assurance can be given that a sale can be completed on terms acceptable to the Company.

The implementation of the Board's strategic initiatives is allowing Pioneer to (i) allocate and focus its investment capital more heavily towards predictable oil and gas basins in North America that have delivered relatively strong and consistent growth and (ii) lower its risk profile by expanding North American unconventional resource investments while reducing exploration expenditures.

The divestiture of the Company's Argentine oil and gas assets will allow the Company to leverage the current commodity price environment to monetize and exit operations in an area that has become characterized by lower operating margins, government-controlled pricing and modest production growth opportunities. The divestiture of the Company's deepwater Gulf of Mexico assets, if successful, will also allow the Company to monetize and exit operations in an area that is characterized by escalating drilling and operating costs and relatively high exploration risk and production volatility.

Financial and Operating Performance

Pioneer's financial and operating performance for the year ended December 31, 2005 included the following highlights:

- Average daily sales volumes on a BOE basis decreased one percent in 2005 as compared to 2004.
- Oil and gas revenues increased 25 percent in 2005 as compared to 2004 primarily as a result of increases in worldwide oil and Argentine and North American gas prices.
- Interest and other income increased by $83.0 million in 2005 as compared to 2004, primarily due to $73.6 million of business interruption insurance claims related to (a) the Hurricane Ivan disruptions and (b) the Fain gas plant fire.
- Other expense increased by $79.1 million in 2005 as compared to 2004, primarily due to increases of $50.5 million and $26.0 million in losses associated with commodity hedge ineffectiveness and debt extinguishments, respectively.
- Income from continuing operations before income taxes and cumulative effect of change in accounting principle increased by 54 percent to $715.5 million in 2005 from $463.1 million in 2004.
- Net income increased to $534.6 million ($3.80 per diluted share) for 2005, as compared to $312.9 million ($2.46 per diluted share) for 2004.
- The Company recognized income from discontinued operations of $110.8 million ($.78 per diluted share) during 2005 attributable to the sale of certain Gulf of Mexico shelf and Canadian properties.
- Outstanding debt decreased by $327.5 million, or 14 percent, as of December 31, 2005 as compared to debt outstanding as of December 31, 2004.
- Net cash provided by operating activities increased by 23 percent to a record $1.3 billion in 2005 as compared to $1.1 billion in 2004.
- The Company declared $.22 per share of common dividends during 2005.
- The Company repurchased 20 million shares of the Company's common stock for $949.3 million during 2005.

- The Company sold three VPPs for net proceeds of $892.6 million.
- Total proved reserves of 986.7 MMBOE at December 31, 2005.

Current Events

Argentina divestiture. During September 2005, the Company announced that it would pursue the sale of its nonoperated assets in Tierra del Fuego. During the Tierra del Fuego sales process, several prospective buyers indicated that they could enhance their value for a transaction in Argentina if it included all of Pioneer's assets. The Company decided that if a buyer presented an attractive offer for all of the Argentine assets, that it would consider exiting Argentina. On January 17, 2006, the Company announced signing an agreement with Apache Corporation to sell all of the Company's interests in Argentina for $675 million (subject to normal closing adjustments). The transaction is expected to close during the latter part of the first quarter or in early April of 2006. The results of operations from these assets will be reflected as discontinued operations in the Company's future financial statements if the sale is closed.

Oooguruk development. In February 2006, the Company announced that it has approved and is commencing the development of the Oooguruk field in shallow waters off the North Slope of Alaska. The Company has a 70 percent working interest in the field. Following the construction of a gravel drilling and production site during the 2006, a subsea flowline and facilities will be installed during 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit. Between 2007 and 2009, Pioneer plans to drill approximately 40 horizontal wells in the Oooguruk field. Total gross capital invested, including projected drilling and facility costs, is expected to range from $450 million to $525 million. First production from these wells is expected to begin in 2008.

South Coast Gas project. In December 2005, the Company announced the final approvals with its partner in the South Coast Gas project. Pioneer has a 45 percent working interest in the project. The project will include subsea tie-back of gas from the Sable field and six additional gas accumulations to the existing production facilities on the F-A platform for transportation via existing pipelines to a GTL plant. The Company has signed a contract for the sale of its share of gas and condensate to the GTL plant. Production is expected to begin during the second half of 2007 and increase to an average of approximately 100 MMcf per day of gas and 3,000 Bbls per day of condensate over the initial phase of the project through 2012. Development drilling related to the project is expected to commence in the first quarter of 2006.

Deepwater Gulf of Mexico divestiture. During September 2005, the Company announced its plans to pursue the divestment of its deepwater Gulf of Mexico assets to reduce the exploration risk and production volatility that have been associated with these properties. The deepwater Gulf of Mexico bid process has been completed and the Company is currently engaged in negotiations for the sale of these assets. No assurance can be given that a sale can be completed on terms acceptable to the Company. The results of operations from these assets will be reflected as discontinued operations in the Company's future financial statements if the divestiture is completed.

Acquisitions

Evergreen merger. On September 28, 2004, Pioneer completed a merger with Evergreen. Pioneer acquired the common stock of Evergreen for a total purchase price of approximately $1.8 billion, which was comprised of cash and Pioneer common stock. At the merger date, Evergreen's proved reserves were approximately 262 MMBOE. Evergreen was primarily engaged in the production, development, exploration and acquisition of North American unconventional gas and was one of the leading developers of CBM reserves in the United States. Evergreen's operations were principally focused on developing and expanding its CBM gas field located in the Raton Basin in southern Colorado. Evergreen also had operations in the Piceance Basin in western Colorado, the Uinta Basin in eastern Utah and the Western Canada Sedimentary Basin.

Permian Basin and Onshore Gulf Coast areas. In July 2005, the Company completed the purchase of approximately 70 MMBOE of substantially undeveloped proved oil reserves in the United States core areas of the Permian Basin and South Texas for $176.9 million. The assets acquired provide an estimated 800 undrilled well locations.

Divestitures

Volumetric production payments. During January 2005, the Company sold two percent of its total proved reserves, or 20.5 MMBOE of proved reserves in the Hugoton and Spraberry fields, by means of two VPPs for net proceeds of $592.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements.

During April 2005, the Company sold less than one percent of its total proved reserves, or 7.3 MMBOE of proved reserves in the Spraberry field, by means of a VPP for net proceeds of $300.3 million, including the value attributable to certain derivative hedge agreements assigned to the buyer of the April VPP.

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

Canada and Gulf of Mexico. During May 2005, the Company sold all of its interests in the Martin Creek and Conroy Black areas of northeast British Columbia and the Lookout Butte area of southern Alberta for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During August 2005, the Company sold all of its interests in certain oil and gas properties on the shelf of the Gulf of Mexico for net proceeds of $59.1 million, resulting in a gain of $27.7 million. The historic results of operations of these properties have been removed from the Company's reported income from continuing operations and are included, together with the gains from the divestitures, in income from discontinuing operations, net of taxes.

Gabon divestiture. In October 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owns the interest in the Olowi block for $47.9 million of net proceeds. A gain was recognized during the fourth quarter of 2005 of $47.5 million with no associated income tax effect either in Gabon or the United States. In addition, Pioneer retains the potential, under certain circumstances, to receive additional payments for production from deeper reservoirs discovered on the block.

2006 Outlook and Activities

Commodity prices. World oil prices increased during the year ended December 31, 2005 in response to continued demand growth in Asian economies, hurricane disruptions in the Gulf of Mexico, political unrest and supply disruptions in Middle East and Venezuela and other supply and demand factors. North American gas prices also increased during 2005 in response to continued strong demand fundamentals while supply uncertainties still remain. The Company's outlook for 2006 commodity prices continues to be cautiously optimistic. Significant factors that will impact 2006 commodity prices include developments in Iraq, Iran and other Middle East countries, the extent to which members of the OPEC and other oil exporting nations are able to manage oil supply through export quotas and variations in key North American gas supply and demand indicators. Pioneer will continue to strategically hedge oil and gas price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues.

See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commodity hedge positions at December 31, 2005. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

Preliminary 2006 capital budget. In certain of its prior Annual Reports on Form 10-K, the Company has provided detailed information on its next year capital allocation and first quarter guidance with respect to production costs and expenses. As a result of the uncertainty surrounding the Company's proposed divestitures of its Argentine and deepwater Gulf of Mexico assets, the Company is presently unable to provide similar information for 2006.

The Company has prepared a preliminary capital budget that does not include capital for its Argentine assets but does include limited capital for the Company's deepwater Gulf of Mexico assets. The preliminary budget is approximately $1.3 billion and includes plans to drill 1,000 to 1,100 wells. The Company's preliminary 2006 capital budget is heavily focused on development and extension drilling, including funding for the recently sanctioned Oooguruk and South Coast gas projects. Less than 20 percent of the preliminary 2006 capital budget is for exploration activities. The Company's final allocation of capital during 2006 is subject to the approval of the Board and is dependent on the outcome of the planned divestitures. Accordingly, the final budget may differ materially from the preliminary budget.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled $2.2 billion, $1.8 billion and $1.2 billion during 2005, 2004 and 2003, respectively. The revenue increase during 2005, as compared to 2004, was due to an 18 percent increase in oil prices, a 26 percent increase in NGL prices and a 32 percent increase in gas prices, including the effects of commodity price hedges, partially offset by a one percent decrease in average daily BOE sales volumes. The revenue increase from 2003 to 2004 was due to a 22 percent increase in average daily BOE sales volumes, a 24 percent increase in oil prices, a 32 percent increase in NGL prices and a 14 percent increase in gas prices, including the effects of commodity price hedges.

The following table provides average daily sales volumes from continuing operations, by geographic area and in total, for 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Oil (Bbls):			
United States	25,943	24,700	22,509
Argentina	7,869	8,534	8,687
Canada	210	72	35
Africa	10,065	11,676	1,981
Worldwide	44,087	44,982	33,212
NGLs (Bbls):			
United States	17,402	19,678	20,306
Argentina	1,824	1,546	1,318
Canada	503	425	473
Worldwide	19,729	21,649	22,097
Gas (Mcf):			
United States	497,068	516,294	417,972
Argentina	137,032	121,654	94,128
Canada	36,427	25,606	26,779
Worldwide	670,527	663,554	538,879
Total (BOE):			
United States	126,191	130,428	112,476
Argentina	32,531	30,356	25,694
Canada	6,784	4,764	4,971
Africa	10,065	11,676	1,981
Worldwide	175,571	177,224	145,122

Per BOE average daily production for 2005, as compared to 2004, increased by seven percent in Argentina and by 42 percent in Canada, while average daily sales volumes decreased by three percent in the United States and by 14 percent in Africa.

Average daily sales volumes from continuing operations in the United States was slightly lower in 2005 as compared to 2004 principally due to declining production in the Gulf of Mexico, asset divestitures and downtime at the Fain gas plant offset by a full year of production from the properties acquired in the Evergreen merger.

Argentine average daily sales volumes increased as a result of successful development drilling and increased market demand during Argentina's summer season. The Company has increased its level of capital expenditures in Argentina as the stability of the Argentine peso and the general economic outlook for Argentina has improved and gas prices have increased.

Canadian average daily sales volumes from continuing operations increased due to new production from Canadian properties acquired in the Evergreen merger and production from new wells drilled during 2005.

Production is down in South Africa due to normal production declines and timing of oil shipments, partially offset by continued growth in Tunisia production.

Per BOE average daily production for 2004, as compared to 2003, increased by 16 percent in the United States, increased by 18 percent in Argentina, decreased by four percent in Canada and the Company realized first production from South Africa and Tunisia during 2003. The increased production was principally attributable to (i) a full year of production from the Falcon area, (ii) new production being initiated from the Harrier, Raptor and Tomahawk fields in the Falcon area and at Devils Tower, (iii) fourth quarter production added from the Evergreen merger and (iv) oil sales having first been realized from the Company's Tunisian and South African oil projects during August and October of 2003, respectively. Argentine oil and gas sales volumes increased during 2004 primarily due to incremental production volumes that resulted from the Company's expanded drilling program and higher oil and gas demand during the summer season.

The following table provides average daily sales volumes from discontinued operations during 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Oil (Bbls):			
United States	1,279	1,937	2,016
Canada	28	65	76
Worldwide	1,307	2,002	2,092
NGLs (Bbls):			
United States	65	60	32
Canada	112	492	433
Worldwide	177	552	465
Gas (Mcf):			
United States	4,136	5,545	5,041
Canada	6,489	16,261	14,890
Worldwide	10,625	21,806	19,931
Total (BOE):			
United States	2,033	2,921	2,888
Canada	1,221	3,267	2,991
Worldwide	3,254	6,188	5,879

The following table provides average reported prices from continuing operations, including the results of hedging activities, and average realized prices from continuing operations, excluding the results of hedging activities, by geographic area and in total, for 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Average reported prices:			
Oil (per Bbl):			
United States	$31.09	$29.69	$25.09
Argentina	$36.88	$28.06	$25.62
Canada	$52.12	$48.37	$28.00
Africa	$53.00	$38.12	$29.52
Worldwide	$37.22	$31.60	$25.50
NGL (per Bbl):			
United States	$31.72	$25.05	$19.03
Argentina	$33.17	$29.91	$22.85
Canada	$45.79	$32.03	$24.30
Worldwide	$32.22	$25.54	$19.38
Gas (per Mcf):			
United States	$ 6.83	$ 5.14	$ 4.45
Argentina	$ .88	$ .66	$ .56
Canada	$ 7.67	$ 4.72	$ 4.65
Worldwide	$ 5.66	$ 4.30	$ 3.78
Average realized prices:			
Oil (per Bbl):			
United States	$54.05	$39.54	$29.52
Argentina	$36.88	$29.82	$26.31
Canada	$52.12	$48.37	$28.00
Africa	$53.00	$38.71	$30.07
Worldwide	$50.74	$37.49	$28.71
NGL (per Bbl):			
United States	$31.72	$25.05	$19.03
Argentina	$33.17	$29.91	$22.85
Canada	$45.79	$32.03	$24.30
Worldwide	$32.22	$25.54	$19.38
Gas (per Mcf):			
United States	$ 7.94	$ 5.71	$ 4.91
Argentina	$ .88	$ .66	$ .56
Canada	$ 7.67	$ 5.37	$ 4.79
Worldwide	$ 6.49	$ 4.78	$ 4.15

Hedging activities. The oil and gas prices that the Company reports are based on the market price received for the commodities adjusted by the results of the Company's cash flow hedging activities. The Company utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. During 2005, 2004 and 2003, the Company's commodity price hedges decreased oil and gas revenues from continuing operations by $420.4 million, $211.9 million and $110.7 million, respectively. The effective portions of changes in the fair values of the

Company's commodity price hedges are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedges add volatility to the Company's reported stockholders' equity until the hedge derivative matures or is terminated. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact to oil and gas revenues during 2005, 2004 and 2003 from the Company's hedging activities, the Company's open hedge positions at December 31, 2005 and descriptions of the Company's hedge commodity derivatives. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosures about the Company's commodity related derivative financial instruments.

Subsequent to December 31, 2005, the Company reduced its oil and gas hedge positions by terminating the following swap and collar contracts: (i) 2,000 BPD of March through December 2006 oil swap contracts with a fixed price of $26.29 per Bbl; 1,000 BPD of calendar 2007 oil swap contracts with a fixed price of $31.00 per Bbl; 2,000 BPD of calendar 2008 oil swap contracts with a fixed price of $30.00 per Bbl; 2,000 BPD of March through December 2006 oil collar contracts having a floor price of $50.00 per Bbl and a ceiling price of $96.25 per Bbl; 2,500 BPD of calendar 2007 oil collar contracts having a floor price of $50.00 and a ceiling price of $91.18 per Bbl and (ii) 65,000 MMBtu per day of April through December 2006 gas collar contracts with a weighted average floor price per MMBtu of $6.74 and a weighted average ceiling price per MMBtu of $14.01. The aggregate value of the terminated oil and gas hedge contracts was a liability of $59.4 million on the dates of termination.

Argentina commodity prices. During 2002, the Argentine government implemented a 20 percent tax on oil exports. In 2003, the Company exported approximately five percent of its Argentine oil production. Associated therewith, the Company incurred oil export taxes of $1.2 million for 2003. During 2004 and 2005, the Company did not export any of its Argentine oil production. The export tax has also had the effect of decreasing internal Argentine oil revenues (not only export revenues) by the taxes levied. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso-denominated costs.

In January 2003, at the Argentine government's request, oil producers and refiners agreed to cap amounts payable for certain domestic sales at $28.50 per Bbl, which remained in effect through April 2004. The producers and refiners further agreed that the difference between the actual price and the capped price would be payable once actual prices fall below the $28.50 cap. Subsequently the terms were modified such that while the $28.50 per Bbl payable cap was in place, the refiners would have no obligation to pay producers for sales values that exceeded $36.00 per Bbl. Initially, the refiners and producers also agreed to discount U.S. dollar-denominated oil prices at 90 percent prior to converting to pesos at the current exchange rate for the purpose of invoicing and settling oil sales to Argentine refiners. In May 2004, refiners and producers changed the discount percentage from 90 percent for all price levels to 86 percent if West Texas Intermediate ("WTI") was equal to or less than $36 per Bbl and 80 percent if WTI exceeded $36 per Bbl. All the oil prices are adjusted for normal quality differentials prior to applying the discount.

In 2004, it appeared probable that the price of world oil would remain above the $28.50 cap for the foreseeable future. Given the uncertainty surrounding the timing of when Argentine producers could expect to collect balances outstanding from refiners, the Company ceased recognizing revenue and began recording any excess between the actual sales price pursuant to its oil sales contracts with Argentine refiners that were subject to the price stabilization agreement and the $28.50 price cap as deferred revenue in the balance sheet. The decision by Argentine oil producers and refiners to not renew the price stability agreement beyond April 30, 2004 does not terminate the obligation of refiners to reimburse producers for balances that accumulated from January 2003 through April 2004, if and when the price of WTI falls below $28.50.

In May 2004, the Argentine government increased the export tax from 20 percent to 25 percent. This tax is applied on the sales value after the tax, thus, the net effect of the 20 percent and 25 percent rates is 16.7 percent and 20 percent, respectively. In August 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from the current 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported Bbls as WTI prices per Bbl increase from less than $32.00 to $45.00 and above. The export tax is not deducted in the calculation of royalty payments and expires in February 2007. Given the number of governmental changes during 2005 affecting the realized price the Company receives for its oil sales, no specific predictions can be made about the future of oil prices in Argentina. However, in the short term, the Company expects Argentine oil realizations to be less than oil realizations in the United States.

As a result of the economic emergency law enacted by the Argentine government in January 2002, the Company's gas prices, expressed in U.S. dollars, have also fallen in proportion to the devaluation of the Argentine peso since the end of 2001 due to the pesofication of contracts and freezing of gas prices at the wellhead required by that law. As a baseline, the Company's 2001 realized Argentine gas price was $1.31 per Mcf as compared to $.88, $.66 and $.56 in 2005, 2004 and 2003, respectively.

The unfavorable gas price has acted to discourage gas development activities and increased gas demand. Without development of gas reserves in Argentina, supplies of gas in the country have declined, while demand for gas has been increasing due to the resurgence of the Argentine economy and the higher cost of alternative fuels. Briefly during 2004, gas exports to Chile were curtailed at the direction of the Argentine government. Argentina has also entered into an agreement to import gas from Bolivia at prices starting at approximately $2.00 per Mcf (at the border), including transportation costs. In May 2004, pursuant to a decree, the Argentine government approved measures to permit producers to renegotiate gas sales contracts, excluding those that could affect small residential customers, in accordance with scheduled price increases specified in the decree. The wellhead prices in the decree increased from a 2004 range of $.61 to $.78 per Mcf to a range of $.87 to $1.04 per Mcf after July 1, 2005, depending on the region where the gas is produced. No further gas price increases beyond July 2005 have occurred. Other than an expectation that gas prices will be permitted to increase gradually over time, as has already been demonstrated by the governing authorities, no specific predictions can be made about the future of gas prices in Argentina. However, the Company expects Argentine gas realizations to be less than gas realizations in the United States.

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for further discussion of commodity prices in Argentina.

Interest and other income. The Company recorded interest and other income totaling $97.1 million, $14.1 million and $12.3 during 2005, 2004 and 2003, respectively. The increase in interest and other income during 2005, as compared to 2004, is primarily attributable to the recognition of $73.6 million in business interruption insurance claims, of which $59.4 million relates to Hurricane Ivan and $14.2 million to the Fain plant fire. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding interest and other income.

Gain on disposition of assets. The Company recorded gains on disposition of assets of $60.5 million, $39,000 and $1.3 million during 2005, 2004 and 2003, respectively.

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

During 2005 the Company also recognized gains on the sale of certain assets in Canada and the shelf of the Gulf of Mexico of approximately $166.1 million. However, pursuant to SFAS 144 the gain and the results of operations from these assets have been reclassified to discontinued operations.

The net cash proceeds from asset divestitures during 2005, 2004 and 2003 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 Notes N and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Oil and gas production costs. The Company recorded production costs of $449.3 million, $316.1 million and $228.2 million during 2005, 2004 and 2003, respectively. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while production taxes and ad valorem taxes are directly related to commodity price changes. Total production costs per BOE increased during 2005 by 44 percent as compared to 2004 primarily due to (i) an increase in production and ad valorem taxes as a result of higher commodity prices, (ii) higher Canadian gas transportation fees, (iii) the retention of operating costs related to VPP volumes sold (approximately $.19 per BOE, during 2005), (iv) new production added from the Evergreen merger which are relatively higher per BOE operating cost properties, (v) decreased production from the lower per BOE production cost deepwater Gulf of Mexico assets and (v) increases in equipment and service costs associated with rising commodity prices.

Total production costs per BOE increased during 2004 by 13 percent as compared to 2003. The increase in total production costs per BOE during 2004 as compared to 2003 was primarily attributable to increases in production volumes and a greater proportion of those volumes coming from the Sable oil field in South Africa, the Devils Tower oil and gas field in the deepwater Gulf of Mexico and, to a lesser extent, the new production added with the Evergreen merger which are higher operating cost properties.

The following tables provide the components of the Company's total production costs per BOE from continuing operations and total production costs per BOE from continuing operations by geographic area for 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Lease operating expenses	$ 5.07	$ 3.63	$3.14
Taxes:			
Ad valorem	.63	.43	.41
Production	.97	.61	.62
Workover costs	.34	.21	.14
Total production costs	$ 7.01	$ 4.88	$4.31

	Year Ended December 31,		
	2005	2004	2003
United States	$ 7.41	$ 4.87	$4.44
Argentina	$ 3.26	$ 2.99	$2.78
Canada	$14.83	$10.79	$9.21
Africa	$ 8.82	$ 7.37	$3.99
Worldwide	$ 7.01	$ 4.88	$4.31

Depletion, depreciation and amortization expense. The Company's total depletion, depreciation and amortization ("DD&A") expense was $8.86, $8.56 and $7.07 per BOE for 2005, 2004 and 2003, respectively. Depletion expense, the largest component of DD&A expense, was $8.53, $8.38 and $6.89 per BOE during 2005, 2004 and 2003, respectively. During 2005, the increase in per BOE depletion expense was primarily due to relatively higher per BOE cost basis Rocky Mountain area production acquired in the Evergreen merger and a higher depletion rate for the Hugoton and Spraberry fields as a result of the VPP volumes sold, partially offset by lower production from higher cost-basis Gulf of Mexico production. Additionally, the Company's depletion expense per BOE (i) increased in Argentina due to downward reserve revisions associated with negative well performance and drilling results in its deep gas play in the Neuquen basin, (ii) increased in Tunisia due to the Company's proved reserves being reduced as a result of the Company's interest in the Adam block being reduced to 20 percent from 28 percent in accordance with the terms of the concession and (iii) decreased in South Africa as a result of upward reserve revisions attributable to better well performance.

During 2004, the increase in per BOE depletion expense was due to a greater proportion of the Company's production being derived from higher cost-basis deepwater Gulf of Mexico and South African developments and downward revisions to proved reserves in Canada in 2003.

The following table provides depletion expense per BOE from continuing operations by geographic area for 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
United States	$ 8.71	$ 8.62	$ 7.06
Argentina	$ 7.13	$ 5.56	$ 4.96
Canada	$12.71	$12.93	$11.42
Africa	$ 7.96	$11.19	$10.69
Worldwide	$ 8.53	$ 8.38	$ 6.89

Impairment of oil and gas properties. The Company reviews its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. During 2005 and 2004, the Company recognized a noncash impairment charge of $.6 million and $39.7 million, respectively, to reduce the carrying value of its Gabonese Olowi field assets as development of the discovery was canceled. See "Critical Accounting Estimates" below and Notes B and S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information pertaining to the Company's accounting policies regarding assessments of impairment and the Gabonese Olowi field impairment, respectively.

Exploration, abandonments, geological and geophysical costs. The following table provides the Company's geological and geophysical costs, exploratory dry hole expense, lease abandonments and other exploration expense from continuing operations by geographic area for 2005, 2004 and 2003:

	United States	Argentina	Canada	Africa and Other	Total
			(In thousands)		
Year ended December 31, 2005:					
Geological and geophysical	$ 66,048	$ 6,603	$ 4,452	$34,353	$111,456
Exploratory dry holes	61,209	9,257	3,468	18,981	92,915
Leasehold abandonments and other	48,770	8,667	1,625	3,318	62,380
	$176,027	$24,527	$ 9,545	$56,652	$266,751
Year ended December 31, 2004:					
Geological and geophysical	$ 51,731	$11,718	$ 4,047	$14,833	$ 82,329
Exploratory dry holes	39,328	7,213	11,131	24,460	82,132
Leasehold abandonments and other	7,925	4,475	3,883	6	16,289
	$ 98,984	$23,406	$19,061	$39,299	$180,750
Year ended December 31, 2003:					
Geological and geophysical	$ 40,783	$ 7,689	$ 4,426	$ 3,903	$ 56,801
Exploratory dry holes	27,015	2,672	9,868	20,250	59,805
Leasehold abandonments and other	4,941	7,715	1,822	108	14,586
	$ 72,739	$18,076	$16,116	$24,261	$131,192

Significant components of the Company's dry hole expense during 2005 included $21.2 related to certain suspended Alaskan well costs, $16.7 million associated with an unsuccessful well in the Falcon Corridor, $9.5 million associated with an unsuccessful Nigerian well, $3.5 million attributable to an unsuccessful well on the Company's El Hamra permit in Tunisia, $5.1 million attributable to an unsuccessful suspended well in the Company's Anaguid permit in Tunisia and various other exploratory wells. The United States leasehold abandonments and other costs during the year ended December 31, 2005 include a $39.8 million increase in East Cameron abandonment obligations that resulted from hurricane damage. During 2005, the Company completed and evaluated 180 exploration/extension wells, 149 of which were successfully completed as discoveries.

Significant components of the Company's dry hole expense during 2004 included \$27.7 million and \$10.5 million on the Company's deepwater Gulf of Mexico Juno and Myrtle Beach prospects, respectively, \$19.0 million on the Company's Gabonese Olowi prospect and \$5.8 million on the Company's Bravo prospect offshore Equatorial Guinea. During 2004, the Company completed and evaluated 103 exploration/extension wells, 58 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled \$124.6 million (\$1.94 per BOE), \$80.3 million (\$1.24 per BOE) and \$60.3 million (\$1.14 per BOE) during 2005, 2004 and 2003, respectively. The increase in general and administrative expense during 2005, as compared to 2004, was primarily due to increases in administrative staff, including staff increases associated with the Evergreen merger, and performance-related compensation costs including the amortization of restricted stock awarded to officers, directors and employees during 2005.

The increase in general and administrative expense during 2004, as compared to 2003, was primarily due to increases in administrative staff, including staff increases associated with the Evergreen merger, and performance-related compensation costs including the amortization of restricted stock awarded to officers, directors and employees during 2004.

Interest expense. Interest expense was \$127.8 million, \$103.4 million and \$91.4 million during 2005, 2004 and 2003, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2005 was 6.5 percent, as compared to 5.4 percent and 5.3 percent for the years ended December 31, 2004 and 2003, respectively, including the effects of interest rate derivatives. The increase in interest expense for 2005 as compared to 2004 was primarily due to increased average borrowings under the Company's lines of credit, primarily as a result of the cash portion of the consideration paid in the Evergreen merger and \$949.3 million of stock repurchases completed during 2005, a \$17.3 million decrease in the amortization of interest rate hedge gains, the assumption of \$300 million of notes in connection with the Evergreen merger and higher interest rates in 2005.

The increase in interest expense for 2004 as compared to 2003 was primarily due to a \$7.9 million decrease in interest rate hedge gains, a \$3.4 million decrease in capitalized interest as the Company completed its major development projects in the Gulf of Mexico and South Africa, increased borrowings under the Company's lines of credit, primarily as a result of the Evergreen merger, and the assumption of \$300 million of notes in connection with the Evergreen merger.

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

Other expenses. Other expenses were \$112.8 million during 2005, as compared to \$33.7 million during 2004 and \$21.3 million during 2003. The increase in other expenses during 2005, as compared to 2004, is primarily attributable to a \$26.5 million loss on the redemption and tender of portions of the Company's senior notes, a \$50.5 million increase in hedge ineffectiveness and a \$3.1 million increase in amortization of noncompete agreements associated with the Evergreen merger. The increase in other expense for 2004 as compared to 2003 was primarily due to an increase in contingency accrual adjustments of \$11.8 million. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a detailed description of the components included in other expenses.

Income tax benefits (provisions). The Company recognized income tax provisions on continuing operations of \$291.7 million and \$164.2 million during 2005 and 2004, respectively, and income tax benefits on continuing operations of \$67.4 million during 2003. The 2003 deferred United States federal, state and local tax benefits include a \$197.7 million benefit from the reversal of the Company's valuation allowances against United States deferred tax assets.

The Company's effective tax rate of 40.8 percent for the year ended December 31, 2005 differs from the combined United States federal and state statutory rate of approximately 36.5 percent primarily due to:

- The second quarter reversal of the $26.9 million tax benefit recorded in 2004 as a result of the cancellation of the development of the Olowi block and the Company's decision to exit Gabon. The Company reversed the tax benefit as a result of signing an agreement in June 2005 to sell its shares in the subsidiary that owns the interest in the Olowi block which made it more likely than not that the Company would not realize the originally recorded tax benefit,
- The Company recognized a gain of approximately $47.5 million in the fourth quarter of 2005 relating to the sale of shares in a subsidiary that owns the interest in the Olowi Block located in Gabon. There is no associated income tax effect either in Gabon or the United States associated with the gain, which partially offsets the effects of the previous item,
- Recording $6.8 million of taxes associated with the repatriation of foreign earnings pursuant to the American Jobs Creation Act of 2004 ("AJCA"),
- Expenses for unsuccessful well costs in foreign locations where the Company receives no expected income tax benefits,
- Foreign tax rate differentials and
- Foreign statutes that differ from those in the United States.

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

Discontinued operations. The Company recognized income from discontinued operations of $110.8 million during 2005, as compared to $13.9 million during 2004 and $17.4 million during 2003. During 2005, the Company sold its interests in (a) the Martin Creek, Conroy Black and Lookout Butte areas in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million and (b) certain assets on the shelf of the Gulf of Mexico for net proceeds of $59.1 million, resulting in a gain of $27.7 million. In 2005, the Company recognized an income tax provision of $73.1 million associated with these divestitures. Pursuant to SFAS 144, the gain and the results of operations from these assets have been reclassified to discontinued operations. See Note V of Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" for additional data on discontinued operations.

The Company's high effective tax rate associated with discontinued operations during 2005 (39.7 percent) was primarily due to:

- A United States deferred tax provision of $17.1 million being triggered by the gain recorded on the Canadian divestiture. The Canadian gain caused the recharacterization of Argentine dividend income from prior years that was previously offset by historical Canadian losses,
- Cash taxes of $2.5 million associated with the repatriation of foreign earnings under the provisions of the AJCA and
- A decrease in the Canadian valuation allowance of $13.4 million, which partially offset the above two items. The Canadian divestiture utilized a substantial portion of the Company's Canadian tax pools. Consequently, the Company reassessed the likelihood that the remaining Canadian tax attributes will be utilized and determined it is now more likely than not that it will be able to utilize more of its tax pools than previously expected.

For years prior to the Canadian divestiture, the Company's discontinued operations reflect no Canadian tax provisions due to the Company having maintained a valuation allowance related to its Canadian deferred tax assets. During those prior years, management's expectation was that it was likely that the Company would not realize its Canadian deferred tax assets. Therefore, in accordance with GAAP, portions of the Canadian valuation allowance were released only to the extent that Canadian income was recorded, thereby offsetting any tax provisions.

The Company's effective tax rate for United States discontinued operations during 2005, 2004 and 2003 was approximately 36.5 percent.

Cumulative effect of change in accounting principle. The Company adopted the provisions of SFAS 143 on January 1, 2003 and recognized a $15.4 million benefit from the cumulative effect of change in accounting principle, net of $1.3 million of deferred income taxes.

Capital Commitments, Capital Resources and Liquidity

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

Payments for acquisitions, net of cash acquired. In 2004, the Company paid $880.4 million of cash, net of $12.1 million of cash acquired, to complete the Evergreen merger. As noted above, the Company also assumed $300 million principal amount of Evergreen notes and other current and noncurrent obligations associated with the Evergreen merger. As is further discussed in "Financing activities" below, and in Notes C and F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data", the Company financed the cash costs utilizing credit facilities in place at the time of the merger.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2005, 2004 and 2003 totaled $1.1 billion, $562.9 million and $662.6 million, respectively. The Company's 2005, 2004 and 2003 expenditures for additions to oil and gas properties were internally funded by $1.3 billion, $1.1 billion and $738.1 million, respectively, of 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 preliminary capital budget for 2006 is expected to be approximately $1.3 billion. The Company believes that proceeds from asset divestitures and net cash provided by operating activities during 2006, based on the current price environment, will be sufficient to fund the 2006 capital expenditures budget.

Off-balance sheet arrangements. From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2005, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, (iv) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future) and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "Contractual obligations" below for more information regarding the Company's off-balance sheet arrangements.

Contractual obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, other liabilities, transportation commitments and VPP obligations.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2005:

	Payments Due by Year			
	2006	2007 and 2008	2009 and 2010	Thereafter
	(In thousands)			
Long-term debt(a)	$ —	$ 382,075	$ 900,000	$ 882,985
Operating leases(b)	57,931	70,686	29,546	5,642
Drilling commitments(c)	172,354	118,497	5,977	—
Derivative obligations(d)	318,852	430,495	—	—
Other liabilities(e)	114,942	63,796	19,415	64,503
Transportation commitments(f)	67,222	136,876	134,614	234,986
VPP obligations(g)	190,327	339,370	238,121	87,020
	$921,628	$1,541,795	$1,327,673	$1,275,136

(a) See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The amounts included in the table above represent principal maturities only.

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

(c) Drilling commitments represent future minimum expenditure commitments under contracts that the Company was a party to on December 31, 2005 for drilling rig services and well commitments. During February 2006, the Company entered into a drilling contract under which the Company is obligated to expend $27.4 million during 2007.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2005. These liabilities include $.9 million of current liabilities that are fixed in amount and are not subject to continuing market risk. The ultimate settlement amounts of the remaining portions of the Company's derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative obligations.

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

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

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

Environmental contingency. A subsidiary of the Company has been notified by a letter from the Texas Commission on Environmental Quality ("TCEQ") dated August 24, 2005 that the TCEQ considers the subsidiary to be a potentially responsible party with respect to the Dorchester Refining Company State Superfund Site located in Mount Pleasant, Texas. The subsidiary, which was acquired by the Company in 1991, owned a refinery located at the Mount Pleasant site from 1977 until 1984. According to the TCEQ, this refinery was responsible for releases of hazardous substances into the environment. The Company does not know the nature and extent of the alleged contamination, the potential costs of remediation, or the portion, if any, of such costs that may be allocable to the Company's subsidiary. However, based on the limited information currently available and assessed regarding this matter, the Company has no reason to believe that it may have a material adverse effect on its future financial condition, results of operations or liquidity. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding this matter as well as other environmental and legal contingencies involving the Company.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of nonstrategic assets. The Company expects that these resources will be sufficient to fund its capital commitments during 2006 and for the foreseeable future.

Asset divestitures. During May 2005, the Company sold all of its interests in the Martin Creek, Conroy Black and Lookout Butte oil and gas properties in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During August 2005, the Company sold all of its interests in certain oil and gas properties on the shelf of the Gulf of Mexico for net proceeds of $59.1 million, resulting in a gain of $27.7 million. During October 2005, the Company sold all of its shares in a subsidiary that owns the interest in the Olowi block in Gabon for net proceeds of $47.9 million, resulting in a gain of $47.5 million. The net cash proceeds from these divestitures were used to reduce outstanding indebtedness.

During January 2005, the Company sold two percent of its total proved reserves, or 20.5 MMBOE of proved reserves, by means of two VPPs for net proceeds of $592.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to reduce outstanding indebtedness.

During April 2005, the Company sold less than one percent of its total proved reserves, or 7.3 MMBOE of proved reserves, by means of another VPP for net proceeds of $300.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPP were initially used to reduce outstanding indebtedness.

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

Operating activities. Net cash provided by operating activities during 2005, 2004 and 2003 was $1.3 billion, $1.1 billion and $738.1 million, respectively. The increase in net cash provided by operating activities in 2005, as compared to that of 2004, was primarily due to higher commodity prices. The increase in net cash provided by operating activities in 2004, as compared to that of 2003, was primarily due to increased production volumes and higher commodity prices.

Investing activities. Net cash provided by investing activities during 2005 was $84.7 million, as compared to net cash used in investing activities during 2004 and 2003 of $1.5 billion and $636.7 million, respectively. The decrease in net cash used in investing activities during 2005, as compared to 2004, was primarily due to (i) $1.2 billion in proceeds from asset divestitures in 2005 which included $892.6 million of net proceeds received from VPPs sold during 2005, (ii) $880.4 million of cash consideration paid in 2004 in connection with the Evergreen merger and (iii) offset by an increase of $560.4 million in additions to oil and gas properties. The increase in net cash used in investing activities during 2004 as compared to 2003 was primarily due to $880.4 million of cash consideration paid in the third quarter of 2004 in connection with the Evergreen merger. See "Results of Operations" above and Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Financing activities. Net cash used in financing activities was $1.4 billion and $91.7 million during 2005 and 2003, respectively. Net cash provided by financing activities during 2004 was $414.3 million. During 2005, financing activities were comprised of $353.6 million of net principal repayments on long-term debt, $78.3 million of payments of other noncurrent liabilities, primarily comprised of cash settlements of acquired hedge obligations, $30.3 million of dividends paid and $949.3 million of treasury stock purchases, partially offset by $41.6 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. During 2004, financing activities were comprised of $553.4 million of net principal borrowings on long-term debt, $54.3 million of payments of other noncurrent liabilities, primarily comprised of settlements of fair value and acquired hedge obligations and other financial obligations, $26.6 million of dividends paid and $92.3 million of treasury stock purchases, partially offset by $35.1 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. During 2003, financing activities were comprised of $105.5 million of net principal payments on long-term debt, $14.1 million of payments of other noncurrent liabilities, $2.8 million of payments for deferred loan fees and $2.3 million of treasury stock purchases, partially offset by $33.0 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases.

During April 2005, $131.0 million of the Company's 8⅞% senior notes due 2005 matured and were repaid. During 2005, the Company also redeemed the remaining $64.0 million and $16.2 million, respectively, of aggregate principal amount of its 9⅝% senior notes due 2010 and its 7.50% senior notes due 2012. During September 2005, the Company accepted tenders to purchase $188.4 million in principal amount of the 5.875% senior notes due 2012 for $199.9 million. The Company utilized unused borrowing capacity under its line of credit to fund these financing activities.

During September 2005, the Company announced that the Board had approved a new share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock, $650 million of which was immediately initiated. As of December 31, 2005, the Company had expended $640.7 million of the $1 billion repurchase program through (i) open market purchases and (ii) a repurchase plan adopted by the Company conforming to the requirements of Rule 10b5-1 of the Exchange Act. The remaining $350 million is subject to the completion of the planned deepwater Gulf of Mexico and Argentine divestments. During 2005 and 2004, the Company expended a total of $949.3 million to acquire 20.0 million shares of treasury stock and $92.3 million to acquire 2.8 million shares of treasury stock, respectively.

During September 2005, the Company entered into an amended credit facility that provides for initial aggregate loan commitments of $1.5 billion and a five-year term (the "Amended Credit Agreement"). In connection with the funding of the Amended Credit Agreement on September 30, 2005, all amounts outstanding under a 364-day credit facility, which was established to fund the Evergreen purchase in September 2004, were retired and the 364-day credit facility terminated.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal source of short-term liquidity is the Amended Credit Agreement. There were $900 million of outstanding borrowings under the Amended Credit Agreement as of December 31, 2005. Including $80.3 million of undrawn and outstanding letters of credit under the Amended Credit Agreement, the Company had $519.7 million of unused borrowing capacity as of December 31, 2005.

The announced plans to divest the Company's Argentine assets and deepwater Gulf of Mexico assets, if successful, will have a positive impact on Pioneer's future liquidity. Proceeds from one or both of these planned divestitures may be used to (i) pay down existing borrowings on the Amended Credit Agreement, (ii) complete the $1 billion share repurchase, (iii) reduce existing obligations, (iv) fund capital commitments or (v) fund working capital needs. Also, the Company may decide to maintain a certain level of any proceeds in cash and investments for future liquidity purposes. There can be no assurances that the Company will successfully conclude the announced plans to divest the Argentine assets or deepwater Gulf of Mexico assets.

Debt ratings. The Company receives debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investor Services, Inc. ("Moody's"), which are subject to regular reviews. During the fourth quarter of 2005, S&P cut the Company's corporate credit rating to BB+ with a stable outlook from BBB-. During January 2006, Moody's cut the Company's corporate credit rating to Ba1 with a negative outlook from Baa3. S&P and Moody's consider many factors in determining the Company's ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. As a result of the downgrades, the interest rate and fees the Company pays on the Amended Credit Agreement have increased and additional debt covenant requirements under the Amended Credit Agreement were triggered. Subsequent to December 31, 2005, as a result of the Company's downgrades by the rating agencies, the Company has issued or may be required to issue additional letters of credits of approximately $73 million pursuant to agreements that contain provisions with rating triggers. The individual downgrades are not expected to materially affect the Company's financial position or liquidity, but could negatively impact the Company's ability to obtain additional financing or the interest rate and fees associated with such additional financing.

Book capitalization and current ratio. The Company's book capitalization at December 31, 2005 was $4.3 billion, consisting of debt of $2.1 billion and stockholders' equity of $2.2 billion. Consequently, the Company's debt to book capitalization increased to 48 percent at December 31, 2005 from 46 percent at December 31, 2004. The Company's ratio of current assets to current liabilities was .60 to 1.00 at December 31, 2005 as compared to .72 to 1.00 at December 31, 2004. The decline in the Company's ratio of current assets to current liabilities was primarily due to its current derivative liabilities as a result of higher commodity prices and current deferred revenue as a result of the VPPs.

Critical Accounting Estimates

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

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 judgments about estimates of future uncertainties.

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

On January 1, 2003, the Company adopted the provisions of SFAS 143. SFAS 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets. SFAS 143, together with the related FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an Interpretation of FASB Statement No. 143" ("FIN 47"), requires the Company to record a separate liability for the discounted present value of the Company's asset retirement obligations, with an offsetting increase to the related oil and gas properties on the balance sheet.

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

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During 2005, 2004 and 2003, the Company recognized exploration, abandonment, geological and geophysical expense from continuing operations of $266.8 million, $180.8 million and $131.2 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, 2005, 2004 and 2003 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

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

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2005 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the Standardized Measure on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. See "Item 1A. Risk Factors" for additional information regarding estimates of reserves and future net revenues.

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

Impairment of proved oil and gas properties. The Company reviews its long-lived proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon its outlook of future commodity prices and net cash flows that may be generated by the properties and if a significant downward revision has occurred to the estimated proved reserves. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated.

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

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

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

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

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

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

Assessments of functional currencies. Management determines the functional currencies of the Company's subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The U.S. dollar is the functional currency of all of the Company's 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, 2005 and 2004 reflect management's assumptions regarding some uncertainties unique to Argentina's current economic situation. 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. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the assumptions utilized in the preparation of these financial statements.

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets will be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurances that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period. As of December 31, 2005, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to certain foreign tax jurisdictions.

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

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

New Accounting Pronouncements

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

SFAS 123(R). In December 2004, the FASB issued SFAS No. 123 (revised 2004), “Share-Based Payment” (“SFAS 123(R)”), which is a revision of SFAS No. 123, “Accounting for Stock-Based Compensation” (“SFAS 123”). SFAS 123(R) supersedes Accounting Principles Bulletin Opinion No. 25, “Accounting for Stock Issued to Employees” (“APB 25”) and amends SFAS No. 95, “Statement of Cash Flows”. Generally, the approach in SFAS 123(R) is similar to the approach described in SFAS 123. However, SFAS 123(R) will require all share-based payments to employees, including grants of employee stock options, to be recognized as stock-based compensation expense in the Company’s Consolidated Statements of Operations based on their fair values. Pro forma disclosure is no longer an alternative.

SFAS 123(R) must be adopted no later than January 1, 2006 and permits public companies to adopt its requirements using one of two methods:

- A “modified prospective” method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123(R) for all share-based payments granted after the adoption date and based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the adoption date.
- A “modified retrospective” method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

The Company adopted the provisions of SFAS 123(R) on January 1, 2006 using the modified prospective method.

As permitted by SFAS 123, the Company accounted for share-based payments to employees prior to January 1, 2006 using the intrinsic value method prescribed by APB 25 and related interpretations. As such, the Company generally did not recognize compensation expense associated with employee stock option grants. The Company has not issued stock options to employees since 2003. Consequently, the adoption of SFAS 123(R)’s fair value method will not have a significant impact on the Company’s future result of operations or financial position. Had the Company adopted SFAS 123(R) in prior periods, the impact would have approximated the impact of SFAS 123 as described in the pro forma disclosures in Note B of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data”. The adoption of SFAS 123(R) will have no effect on future results of operations related to the Company’s unvested outstanding restricted stock awards. The Company estimates that the adoption of SFAS 123(R), based on estimated outstanding unvested stock options, will result in compensation charges of approximately $1.0 million during 2006.

The Company’s ESPP that allows eligible employees to annually purchase the Company’s common stock at a discount. The provisions of SFAS 123(R) will cause the ESPP to be a compensatory plan. However, the change in accounting for the ESPP is not expected to have a material impact on the Company’s financial position, future results of operations or liquidity. Historically, the ESPP compensatory amounts have been nominal. See Note H of Notes to Consolidated Financial Statements in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the ESPP.

SFAS 123(R) also requires that tax benefits in excess of recognized compensation expenses be reported as a financing cash flow, rather than an operating cash flow as required under prior literature. This requirement may serve to reduce the Company's future cash flows from operating activities and increase future cash flows from financing activities, to the extent of associated tax benefits that may be realized in the future.

FIN 47. In March 2005, the FASB issued FIN 47. FIN 47 clarifies that conditional asset retirement obligations meet the definition of liabilities and should be recognized when incurred if their fair values can be reasonably estimated. The Company adopted the provisions of FIN 47 effective on December 31, 2005. The adoption of FIN 47 had no impact on the Company's financial position or results of operations.

FSP FAS 19-1. In April 2005, the FASB issued Staff Position No. FAS 19-1, "Accounting for Suspended Well Costs ("FSP FAS 19-1"). FSP FAS 19-1 amended SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19"), to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19-1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the second quarter of 2005. See Note D of Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's exploratory well costs. The adoption of FSP FAS 19-1 did not impact the Company's consolidated financial position or results of operations.

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, 2005 and 2004, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices. Although certain derivative contracts to which the Company has been a party to did not qualify as hedges, the Company does not enter into derivative or other financial instruments for trading purposes.

The fair value of the Company's derivative contracts are determined based on counterparties' estimates and valuation models. The Company did not change its valuation method during 2005. During 2005, the Company was a party to commodity, interest rate and foreign exchange rate swap contracts and commodity collar contracts. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2005:

	Derivative Contract Liabilities			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
		(In thousands)		
Fair value of contracts outstanding as of December 31, 2004	$(406,546)	$ —	$ —	$(406,546)
Changes in contract fair values(a)	(872,808)	(4,614)	(43)	(877,465)
Contract maturities	497,474	—	43	497,517
Contract terminations	33,403	4,614	—	38,017
Fair value of contracts outstanding as of December 31, 2005	$(748,477)	$ —	$ —	$(748,477)

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

Quantitative Disclosures

Foreign exchange rate sensitivity. From time-to-time, the Company's Canadian subsidiary enters into short-term forward currency agreements to purchase Canadian dollars with U.S. dollar gas sales proceeds. The Company does not designate these derivatives as hedges due to their short-term nature. There were no outstanding forward currency agreements at December 31, 2005.

Interest rate sensitivity. The following tables provide information about other financial instruments to which the Company was a party as of December 31, 2005 and 2004 and that were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2005 and 2004. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 15, 2006. As of December 31, 2005, the Company was not a party to material derivatives that would subject it to interest rate sensitivity.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2005

	Year Ending December 31,							Liability Fair Value at December 31,
	2006	2007	2008	2009	2010	Thereafter	Total	2005
	(In thousands, except interest rates)							
Total Debt:								
Fixed rate principal maturities(a)	$ —	$32,075	$350,000	$ —	$ —	$882,985	$1,265,060	$(1,369,404)
Weighted average interest rate (%)	6.31	6.29	6.16	6.16	6.16	6.16		
Variable rate maturities	$ —	$ —	$ —	$ —	$900,000	$ —	$ 900,000	$ (900,000)
Average interest rate (%)	5.88	6.00	6.02	6.10	6.16	—		

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

Interest Rate Sensitivity
Debt Obligations as of December 31, 2004

	Year Ending December 31,							Liability Fair Value at December 31,
	2005	2006	2007	2008	2009	Thereafter	Total	2004
	(In thousands, except interest rates)							
Total Debt:								
Fixed rate principal maturities(a)	$130,950	$ —	$32,075	$350,000	$ —	$1,151,579	$1,664,604	$(1,846,110)
Weighted average interest rate (%)	6.46	6.40	6.39	7.04	7.04	7.04		
Variable rate maturities	$ —	$800,000	$ —	$ 28,000	$ —	$ —	$ 828,000	$ (828,000)
Average interest rate (%)	3.89	4.77	5.13	5.49	—	—		

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

Commodity price sensitivity. The following tables provide information about the Company's oil and gas derivative financial instruments that were sensitive to changes in oil and gas prices as of December 31, 2005 and 2004. As of December 31, 2005 and 2004, all of the Company's oil and gas derivative financial instruments qualified as hedges.

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

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

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2005

	Year Ending December 31, 2006	2007	2008	Liability Fair Value at December 31, 2005 (In thousands)
Oil Hedge Derivatives:				
Average daily notional Bbl volumes(a):				
Swap contracts(b)	10,000	13,000	17,000	$(441,189)
Weighted average fixed price per Bbl	$ 31.69	$ 30.89	$ 29.21	
Collar contracts(b)	9,129	4,500	—	$ (21,879)
Weighted average ceiling price per Bbl	$ 74.92	$ 90.43	$ —	
Weighted average floor price per Bbl	$ 44.25	$ 50.00	$ —	
Average forward NYMEX oil prices(c)	$ 62.72	$ 65.52	$ 64.84	

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

(b) Subsequent to December 31, 2005, the Company reduced its oil hedge positions by terminating the following oil swap and collar contracts: (i) 2,000 BPD of March through December 2006 swap contracts with a fixed price of $26.29 per Bbl; 1,000 BPD of calendar 2007 swap contracts with a fixed price of $31.00 per Bbl; and 2,000 BPD of calendar 2008 swap contracts with a fixed price of $30.00 per Bbl and (ii) 2,000 BPD of March through December 2006 collar contracts having a floor price of $50.00 per Bbl and a ceiling price of $96.25 per Bbl and 2,500 BPD of calendar 2007 collar contracts having a floor price of $50.00 and ceiling prices of $91.18 per Bbl. The aggregate fair value of the terminated oil swap and collar contracts represented a liability of $63.5 million on the dates of termination.

(c) The average forward NYMEX oil prices are based on February 15, 2006 market quotes.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2004

	Year Ending December 31, 2005	2006	2007	2008	2009	2010	2011	2012	Liability Fair Value at December 31, 2004 (In thousands)
Oil Hedge Derivatives:									
Average daily notional Bbl volumes:									
Swap contracts(a)	27,000	14,500	17,000	21,000	3,500	1,000	2,000	2,000	$(261,111)
Weighted average fixed price per Bbl	$ 27.97	$ 34.12	$ 32.59	$ 30.72	$36.48	$36.10	$35.93	$35.86	
Collar contracts	—	3,500	—	—	—	—	—	—	$ (2,278)
Weighted average ceiling price per Bbl	$ —	$ 41.95	$ —	$ —	$ —	$ —	$ —	$ —	
Weighted average floor price per Bbl	$ —	$ 35.00	$ —	$ —	$ —	$ —	$ —	$ —	
Average forward NYMEX oil prices(b)	$ 48.58	$ 45.26	$ 43.08	$ 41.01	$40.36	$39.91	$39.71	$39.51	

(a) Subsequent to December 31, 2004, the Company conveyed to the purchaser of the January VPPs the following oil swap contracts which were included in the schedule above: (i) 4,500 Bbls per day of 2006 oil sales at a weighted average fixed price per Bbl of $39.53, (ii) 4,000 Bbls per day of 2007 oil sales at a weighted average fixed price per Bbl of $38.14, (iii) 4,000 Bbls per day of 2008 oil sales at a weighted average fixed price per Bbl of $37.15, (iv) 3,500 Bbls per day of 2009 oil sales at a weighted average fixed price per Bbl of

$36.48, (v) 1,000 Bbls per day of 2010 oil sales at a weighted average fixed price per Bbl of $36.10, (vi) 2,000 Bbls per day of 2011 oil sales at a weighted average fixed price per Bbl of $35.93 and (vii) 2,000 Bbls per day of 2012 oil sales at a weighted average fixed price per Bbl of $35.86.

(b) The average forward NYMEX oil prices are based on February 18, 2005 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2005

	Year Ending December 31,			Liability Fair Value at December 31, 2005
	2006	2007	2008	(In thousands)
Gas Hedge Derivatives(a):				
Average daily notional MMBtu volumes(b):				
Swap contracts	73,842	29,195	5,000	$(213,543)
Weighted average fixed price per MMBtu	$ 4.30	$ 4.28	$ 5.38	
Collar contracts (c)	183,685	215,000	—	$ (71,866)
Weighted average ceiling price per MMBtu	$ 13.76	$ 11.84	$ —	
Weighted average floor price per MMBtu	$ 6.62	$ 6.57	$ —	
Average forward NYMEX gas prices(d)	$ 7.81	$ 8.99	$ 8.76	

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

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

(c) Subsequent to December 31, 2005, the Company reduced its gas hedge positions by terminating the following gas collar contracts which were included in the table above: 65,000 MMBtu per day of April through December 2006 gas sales at a weighted average floor price per MMBtu of $6.74 and a weighted average ceiling price per MMBtu of $14.01. The aggregate fair value of the terminated gas collar contracts represented an asset of $4.1 million on the dates of termination.

(d) The average forward NYMEX gas prices are based on February 15, 2006 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2004

	Year Ending December 31,					Liability Fair Value at December 31, 2004
	2005	2006	2007	2008	2009	(In thousands)
Gas Hedge Derivatives(a):						
Average daily notional MMBtu volumes:						
Swap contracts(b)	284,055	103,534	55,000	30,000	25,000	$(142,858)
Weighted average fixed price per MMBtu	$ 5.22	$ 4.68	$ 4.69	$ 5.06	$ 4.72	
Collar contracts	—	5,000	—	—	—	$ (299)
Weighted average ceiling price per MMBtu	$ —	$ 7.15	$ —	$ —	$ —	
Weighted average floor price per MMBtu	$ —	$ 5.25	$ —	$ —	$ —	
Average forward NYMEX gas prices(c)	$ 6.29	$ 6.47	$ 6.14	$ 5.81	$ 5.50	

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

(b) Subsequent to December 31, 2004, the Company conveyed to the purchaser of the January VPPs the following gas swap contracts which were included in the table above: (i) 9,151 MMBtu per day 2005 gas sales at a weighted average fixed price per MMBtu of $6.17, (ii) 33,534 MMBtu per day 2006 gas sales at a weighted average fixed price per MMBtu of $5.78, (iii) 30,000 MMBtu per day 2007 gas sales at a weighted average fixed price per MMBtu of $5.32, (iv) 25,000 MMBtu per day 2008 gas sales at a weighted average fixed price per MMBtu of $5.00 and (v) 25,000 MMBtu per day of 2009 gas sales at a weighted average fixed price per MMBtu of $4.72.

(c) The average forward NYMEX gas prices are based on February 18, 2005 market quotes.

Qualitative Disclosures

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

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

Foreign currency, operations and price risk. International investments represent, and are expected to continue to represent, a significant portion of the Company's total assets. Pioneer currently has international operations in Africa, Argentina and Canada, which represent nine, eight and five percent of the Company's 2005 oil and gas revenues, respectively. Pioneer continues to identify and evaluate other international opportunities. As a result of such foreign operations, Pioneer's financial results could be affected by factors such as changes in foreign currency exchange rates, weak economic conditions or changes in political climates in these foreign countries.

The Company's international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. For example:

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

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

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

Argentina. During the decade of the 1990s, Argentina's government pursued free market policies, including the privatization of state-owned companies, deregulation of the oil and gas industry, tax reforms to equalize tax rates for domestic and foreign investors, liberalization of import and export laws and the lifting of exchange controls. The cornerstone of these reforms was the 1991 convertibility law that established an exchange rate of one Argentine peso to one U.S. dollar. These policies were successful as evidenced by the elimination of inflation and substantial economic growth during the early to mid-1990s. However, throughout the decade, the Argentine government failed to balance its fiscal budget, repeatedly incurring significant fiscal deficits such that by the end of 2001 Argentina had accumulated $130 billion of debt.

During 2001, Argentina found itself in a critical economic situation with the combination of high levels of external indebtedness, a financial and banking system in crisis, a country risk rating that had reached levels beyond the historical norm, a high level of unemployment and an economic contraction that had lasted four years.

Late in 2001, the country was unable to obtain additional funding from the International Monetary Fund. Economic instability increased, resulting in substantial withdrawals of cash from the Argentine banking system over a short period of time. The government was forced to implement monetary restrictions and placed limitations on the transfer of funds out of the country without the authorization of the Central Bank of the Republic of Argentina. President De la Rua and his entire administration were forced to resign in the face of public dissatisfaction. After his resignation in December 2001, there was, for a few weeks, a revolving door of presidents that were appointed to office by Argentina's Congress, but quickly resigned in reaction to public outcry. Eduardo Duhalde was appointed President of Argentina in January 2002 to hold office until the 2003 Presidential election.

In January 2002, the government defaulted on a significant portion of Argentina's $130 billion of debt and the national Congress passed Emergency Law 25,561, which, among other things, overturned the long standing, but unsustainable, convertibility plan. The government adopted a floating rate of exchange in February 2002. Two specific provisions of the Emergency Law directly impact the Company. First, a tax on the value of hydrocarbon exports was established effective March 1, 2002. The second provision was the requirement that domestic commercial transactions, or contracts, for sales in Argentina that were previously denominated in U.S. dollars be converted to pesos (i.e., pesofication) at an exchange rate to be negotiated between sellers and buyers. Furthermore, the government placed a price freeze on gas prices at the wellhead. With the price of gas pesofied and frozen, the U.S. dollar-equivalent price of gas in Argentina fell in direct proportion to the level of devaluation.

The abandonment of the convertibility plan and the decision to allow the peso to float in international exchange markets resulted in significant devaluation of the peso. By September 30, 2002, the peso-to-U.S. dollar exchange rate had increased from 1:1 to 3.74:1. However, since the end of the third quarter of 2002, Argentina's economy has shown signs of stabilization. At December 31, 2005, the peso-to-U.S. dollar exchange rate was 3.03:1.

In Argentina, unlike Pioneer's other operating areas, there have been significant factors that have kept the commodity prices, in general, below those of the world markets and may continue to do so. The following is a discussion of the matters affecting Argentine commodity prices:

- ***Oil Prices*** — In January 2002, the Argentine government devalued the peso and enacted an emergency law that, in part, required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, in February 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The export tax is not deducted in the calculation of royalty payments. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in pesos. Export oil sales continue to be valued and paid in U.S. dollars.

  In January 2003, at the Argentine government's request, oil producers and refiners agreed to cap amounts payable for certain domestic sales at $28.50 per Bbl which remained in effect through April 2004. The producers and refiners further agreed that the difference between the actual price and the capped price would be payable once actual prices fall below the $28.50 cap. Subsequently the terms were modified such that while the $28.50 per Bbl payable cap was in place, the refiners would have no obligation to pay producers for sales values that exceeded $36.00 per Bbl. Initially, the refiners and producers also agreed to discount U.S. dollar-denominated oil prices at 90 percent prior to converting to pesos at the current exchange rate for the purpose of invoicing and settling oil sales to Argentine refiners. In May 2004, refiners and producers changed the discount percentage from 90 percent for all price levels to 86 percent if WTI was equal to or less than $36 per Bbl and 80 percent if WTI exceeded $36 per Bbl. All the oil prices are adjusted for normal quality differentials prior to applying the discount.

In May 2004, the Argentine government increased the export tax from 20 percent to 25 percent. This tax is applied on the sales value after the tax, thus, the net effect of the 20 percent and 25 percent rates is 16.7 percent and 20 percent, respectively. In August 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from the current 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported Bbls as WTI prices per Bbl increase from less than $32.00 to $45.00 and above.

On December 24, 2004, the Secretary of Energy issued Administrative Resolution 1679/2004, in order to alleviate shortages in domestic diesel markets by insuring adequate oil supplies to Argentine refiners. The terms of the resolution require producers to submit evidence to the Secretary of Energy that its oil to be exported has been offered to domestic refiners prior to the government's issuance of export permission.

During 2003, the Company exported approximately five percent of its Argentine oil production. Associated therewith, the Company incurred oil export taxes of $1.2 million for 2003. During 2004 and 2005, the Company did not export any of its Argentine oil production. As noted above, the export tax has also had the effect of decreasing internal Argentine oil revenues (not only export revenues) by the taxes levied. The U.S. dollar equivalent value for domestic Argentine oil sales has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso-denominated costs such as labor. Given the number of governmental changes during 2005 affecting the realized price the Company receives for its oil sales, no specific predictions can be made about the future of oil prices in Argentina. However, the Company expects Argentine oil realizations to continue to be less than oil realizations in the United States.

- ***Gas Prices*** — The Company sells its gas to Argentine customers pursuant to (a) peso-denominated contracts, (b) long-term dollar-denominated contracts and (c) spot market sales. As a result of the economic emergency law enacted by the Argentine government in January 2002, the Company's gas prices, expressed in U.S. dollars, have fallen in proportion to the devaluation of the Argentine peso since the end of 2001 due to the pesofication of contracts and the freezing of gas prices at the wellhead required by that law. As a baseline, the Company's 2001 realized gas price was $1.31 per Mcf as compared to $.88, $.66 and $.56 in 2005, 2004 and 2003, respectively.

  The unfavorable gas price has acted to discourage gas development activities and increased gas demand. Without development of gas reserves in Argentina, supplies of gas in the country have declined, while demand for gas has been increasing due to the resurgence of the Argentine economy and the higher cost of alternative fuels. During 2004, gas exports to Chile were curtailed at the direction of the Argentine government and Argentina entered into an agreement to import gas from Bolivia at prices starting at approximately $2.00 per Mcf (at the border), including transportation costs. In May 2004, pursuant to a decree, the Argentine government approved measures to permit producers to renegotiate gas sales contracts, excluding those that could affect small residential customers, in accordance with scheduled price increases specified in the decree. The wellhead prices in the decree increased from a 2004 range of $.61 to $.78 per Mcf to a range of $.87 to $1.04 per Mcf after July 2005, depending on the region where the gas is produced. No further gas price increases beyond July 2005 have occurred. Other than an expectation that gas prices will be permitted to increase gradually over time, as has already been demonstrated by the governing authorities, no specific predictions can be made about the future of gas prices in Argentina. However, the Company expects Argentine gas realizations to be less than gas realizations in the United States.

Canada. The Company views the operating environment in Canada as stable and the economic stability as good. A portion of the Company's Canadian revenues and substantially all of its costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to the U.S. dollar, the Company believes that any currency risk associated with its Canadian operations would not have a material impact on the Company's results of operations.

As of December 31, 2005, 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 á 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, 2005.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2006 expressed an unqualified opinion thereon.

As discussed in Note B to the consolidated financial statements, in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Ernst & Young LLP

Dallas, Texas
February 15, 2006

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,802	$ 7,257
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $5,736 and $5,409 as of December 31, 2005 and 2004, respectively	336,062	209,297
Due from affiliates	1,596	639
Inventories	79,659	40,332
Prepaid expenses	18,091	10,822
Deferred income taxes	158,878	115,206
Other current assets:		
Derivatives	1,246	209
Other, net of allowance for doubtful accounts of $6,425 as of December 31, 2005 and 2004	9,470	9,663
Total current assets	623,804	393,425
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	8,499,253	7,663,446
Unproved properties	313,881	461,170
Accumulated depletion, depreciation and amortization	(2,577,946)	(2,243,549)
Total property, plant and equipment	6,235,188	5,881,067
Deferred income taxes	—	2,963
Goodwill	311,651	320,900
Other property and equipment, net	90,010	78,696
Other assets:		
Derivatives	1,048	—
Other, net of allowance for doubtful accounts of $92 as of December 31, 2005 and 2004	67,533	56,436
	$ 7,329,234	$ 6,733,487
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 330,151	$ 205,153
Due to affiliates	15,053	10,898
Interest payable	40,314	45,735
Income taxes payable	22,470	13,520
Other current liabilities:		
Derivatives	320,098	224,612
Deferred revenue	190,327	—
Other	114,942	44,541
Total current liabilities	1,033,355	544,459
Long-term debt	2,058,412	2,385,950
Derivatives	431,543	182,803
Deferred income taxes	767,329	612,435
Deferred revenue	664,511	—
Other liabilities and minority interests	156,982	176,060
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 146,956,473 and 145,644,828 shares issued at December 31, 2005 and 2004, respectively	1,470	1,456
Additional paid-in capital	3,775,794	3,705,286
Treasury stock, at cost; 18,368,109 and 813,166 shares at December 31, 2005 and 2004, respectively	(882,382)	(27,793)
Deferred compensation	(45,827)	(22,558)
Accumulated deficit	(184,320)	(634,146)
Accumulated other comprehensive income (loss):		
Net deferred hedge losses, net of tax	(506,636)	(241,350)
Cumulative translation adjustment	59,003	50,885
Total stockholders' equity	2,217,102	2,831,780
Commitments and contingencies		
	$ 7,329,234	$ 6,733,487

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, 2005	2004	2003
Revenues and other income:			
Oil and gas	$2,215,677	$1,767,371	$1,208,621
Interest and other	97,050	14,074	12,292
Gain on disposition of assets, net	60,496	39	1,256
	2,373,223	1,781,484	1,222,169
Costs and expenses:			
Oil and gas production	449,320	316,107	228,183
Depletion, depreciation and amortization	568,018	556,264	374,295
Impairment of long-lived assets	644	39,684	—
Exploration and abandonments	266,751	180,750	131,192
General and administrative	124,556	80,302	60,322
Accretion of discount on asset retirement obligations	7,876	8,210	5,040
Interest	127,787	103,387	91,388
Other	112,812	33,687	21,320
	1,657,764	1,318,391	911,740
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	715,459	463,093	310,429
Income tax benefit (provision)	(291,728)	(164,164)	67,368
Income from continuing operations before cumulative effective of change in accounting principle	423,731	298,929	377,797
Income from discontinued operations, net of tax	110,837	13,925	17,382
Income before cumulative effect of change in accounting principle	534,568	312,854	395,179
Cumulative effect of change in accounting principle, net of tax	—	—	15,413
Net income	$ 534,568	$ 312,854	$ 410,592
Basic earnings per share:			
Income from continuing operations before cumulative effect of change in accounting principle	$ 3.09	$ 2.39	$ 3.22
Income from discontinued operations, net of tax	.81	.11	.15
Cumulative effect of change in accounting principle, net of tax	—	—	.13
Net income	$ 3.90	$ 2.50	$ 3.50
Diluted earnings per share:			
Income from continuing operations before cumulative effect of change in accounting principle	$ 3.02	$ 2.35	$ 3.19
Income from discontinued operations, net of tax	.78	.11	.14
Cumulative effect of change in accounting principle, net of tax	—	—	.13
Net income	$ 3.80	$ 2.46	$ 3.46
Weighted average shares outstanding:			
Basic	137,110	125,156	117,185
Diluted	141,417	127,488	118,513

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except dividends per share)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compensation	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Gains (Losses), Net of Tax	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Balance as of January 1, 2003	$1,196	$2,714,567	$ (32,219)	$(14,292)	$(1,298,440)	$ 9,555	$ (5,470)	$1,374,897
Exercise of long-term incentive plan stock options and employee stock purchases	1	4,100	29,183	—	—	—	—	33,284
Purchase of treasury stock	—	—	(2,349)	—	—	—	—	(2,349)
Tax benefits related to stock-based compensation	—	14,666	—	—	—	—	—	14,666
Deferred compensation:								
Compensation deferred	—	1,070	—	(1,070)	—	—	—	—
Deferred compensation included in net income	—	—	—	5,429	—	—	—	5,429
Net income	—	—	—	—	410,592	—	—	410,592
Other comprehensive income (loss):								
Net deferred hedge losses, net of tax:								
Net deferred hedge losses	—	—	—	—	—	(282,165)	—	(282,165)
Net hedge losses included in net income	—	—	—	—	—	117,416	—	117,416
Tax benefits related to net hedge losses	—	—	—	—	—	51,064	—	51,064
Translation adjustment	—	—	—	—	—	—	36,938	36,938
Balance as of December 31, 2003	1,197	2,734,403	(5,385)	(9,933)	(887,848)	(104,130)	31,468	1,759,772
Acquisition of Evergreen Resources, Inc.	254	947,334	—	(6,001)	—	—	—	941,587
Dividends declared ($.20 per common share)	—	—	—	—	(26,557)	—	—	(26,557)
Exercise of long-term incentive plan stock options and employee stock purchases	—	(2,185)	69,848	—	(32,595)	—	—	35,068
Purchase of treasury stock	—	—	(92,256)	—	—	—	—	(92,256)
Tax benefits related to stock-based compensation	—	6,612	—	—	—	—	—	6,612
Deferred compensation:								
Compensation deferred	5	19,122	—	(19,127)	—	—	—	—
Deferred compensation included in net income	—	—	—	12,503	—	—	—	12,503
Net income	—	—	—	—	312,854	—	—	312,854
Other comprehensive income (loss):								
Net deferred hedge losses, net of tax:								
Net deferred hedge losses	—	—	—	—	—	(443,318)	—	(443,318)
Net hedge losses included in net income	—	—	—	—	—	232,758	—	232,758
Tax benefits related to net hedge losses	—	—	—	—	—	73,340	—	73,340
Translation adjustment	—	—	—	—	—	—	19,417	19,417
Balance as of December 31, 2004	1,456	3,705,286	(27,793)	(22,558)	(634,146)	(241,350)	50,885	2,831,780
Dividends declared ($.22 per common share)	—	—	—	—	(30,339)	—	—	(30,339)
Exercise of long-term incentive plan stock options and employee stock purchases	—	1,310	94,670	—	(54,403)	—	—	41,577
Purchase of treasury stock	—	—	(949,259)	—	—	—	—	(949,259)
Tax benefits related to stock-based compensation	—	18,752	—	—	—	—	—	18,752
Deferred compensation:								
Compensation deferred	14	56,146	—	(56,160)	—	—	—	—
Deferred compensation included in net income	—	—	—	26,857	—	—	—	26,857
Forfeitures of deferred compensation	—	(5,700)	—	6,034	—	—	—	334
Net income	—	—	—	—	534,568	—	—	534,568
Other comprehensive income (loss):								
Net deferred hedge losses, net of tax:								
Net deferred hedge losses	—	—	—	—	—	(863,439)	—	(863,439)
Net hedge losses included in net income	—	—	—	—	—	431,581	—	431,581
Tax benefits related to net hedge losses	—	—	—	—	—	166,572	—	166,572
Translation adjustment	—	—	—	—	—	—	8,118	8,118
Balance as of December 31, 2005	$1,470	$3,775,794	$(882,382)	$(45,827)	$ (184,320)	$(506,636)	$59,003	$2,217,102

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,		
	2005	2004	2003
Cash flows from operating activities:			
Net income	$ 534,568	$ 312,854	$ 410,592
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	568,018	556,264	374,295
Impairment of long-lived assets	644	39,684	—
Exploration expenses, including dry holes	147,897	93,063	70,659
Deferred income taxes	236,586	138,877	(78,553)
Gain on disposition of assets, net	(60,496)	(39)	(1,256)
Loss (gain) on extinguishment of debt	25,975	(95)	1,457
Accretion of discount on asset retirement obligations	7,876	8,210	5,040
Discontinued operations	(84,098)	21,587	20,971
Interest expense	6,093	(12,208)	(20,610)
Commodity hedge related activity	21,237	(45,102)	(71,816)
Cumulative effect of change in accounting principle, net of tax	—	—	(15,413)
Amortization of stock-based compensation	26,857	12,503	5,429
Amortization of deferred revenue	(75,773)	—	—
Other noncash items	22,030	17,008	3,509
Change in operating assets and liabilities, net of effects from acquisition and disposition:			
Accounts receivable, net	(128,015)	(73,376)	(10,983)
Inventories	(36,948)	(14,025)	(7,734)
Prepaid expenses	(7,504)	974	(5,598)
Other current assets, net	(226)	262	(602)
Accounts payable	102,116	250	58,603
Interest payable	(7,115)	5,533	(424)
Income taxes payable	8,950	3,372	5,928
Other current liabilities	(13,362)	(14,037)	(5,385)
Net cash provided by operating activities	1,295,310	1,051,559	738,109
Cash flows from investing activities:			
Payments for acquisition, net of cash acquired	(965)	(880,365)	—
Proceeds from disposition of assets, net of cash sold	1,248,581	1,709	35,698
Additions to oil and gas properties	(1,123,297)	(562,907)	(662,563)
Other property additions, net	(39,585)	(36,970)	(9,865)
Net cash provided by (used in) investing activities	84,734	(1,478,533)	(636,730)
Cash flows from financing activities:			
Borrowings under long-term debt	1,203,190	1,157,903	264,725
Principal payments on long-term debt	(1,556,763)	(604,475)	(370,262)
Payment of other liabilities	(78,285)	(54,252)	(14,055)
Exercise of long-term incentive plan stock options and employee stock purchases	41,577	35,068	33,020
Purchase of treasury stock	(949,259)	(92,256)	(2,349)
Payment of financing fees	(1,911)	(1,173)	(2,799)
Dividends paid	(30,339)	(26,557)	—
Net cash provided by (used in) financing activities	(1,371,790)	414,258	(91,720)
Net increase (decrease) in cash and cash equivalents	8,254	(12,716)	9,659
Effect of exchange rate changes on cash and cash equivalents	3,291	674	1,150
Cash and cash equivalents, beginning of year	7,257	19,299	8,490
Cash and cash equivalents, end of year	$ 18,802	$ 7,257	$ 19,299

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2005	2004	2003
Net income	$ 534,568	$ 312,854	$ 410,592
Other comprehensive loss:			
Net deferred hedge losses, net of tax:			
Net deferred hedge losses	(863,439)	(443,318)	(282,165)
Net hedge losses included in net income	431,581	232,758	117,416
Tax benefits related to net hedge losses	166,572	73,340	51,064
Translation adjustment	8,118	19,417	36,938
Other comprehensive loss	(257,168)	(117,803)	(76,747)
Comprehensive income	$ 277,400	$ 195,051	$ 333,845

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

NOTE A. Organization and Nature of Operations

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

On September 28, 2004, the Company completed a merger with Evergreen Resources, Inc. ("Evergreen") that added to the Company's United States and Canadian asset base and expanded its portfolio of development and exploration opportunities in North America. Evergreen's operations were primarily focused on developing and expanding its coal bed methane production from the Raton Basin in southern Colorado.

In accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 141, "Business Combinations", the merger has been accounted for as a purchase of Evergreen by Pioneer. As a result, the financial statements for the Company prior to September 28, 2004 are those of Pioneer only. The accompanying Consolidated Statements of Operations and Consolidated Statements of Cash Flows include the financial results of Evergreen since October 1, 2004. See Note C for additional information regarding the Evergreen merger.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. The Company proportionately consolidates less than 100 percent-owned affiliate partnerships, which it serves as general partner through certain of its wholly-owned subsidiaries, involved in oil and gas producing activities in accordance with Emerging Issues Task Force ("EITF") Abstract Issue No. 00-1, "Investor Balance Sheet and Income Statement Display under the Equity Method for Investments in Certain Partnerships and Other Ventures". The Company owns less than a 20 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

As of December 31, 2005 and 2004, other liabilities and minority interests in the Company's Consolidated Balance Sheets includes \$9.3 million and \$8.7 million, respectively, related to majority-owned subsidiaries, which are related to activities in the United States and Nigeria. The minority interest in the net income of the United States related subsidiaries was \$3.5 million and \$.9 million for 2005 and 2004, respectively, and is included in other expense in the Company's Consolidated Statements of Operations. The minority interest in the net loss of the Nigerian subsidiary was \$5.2 million for 2005 and is included in interest and other income in the Company's Consolidated Statements of Operations.

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

Argentina devaluation. 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. As of December 31, 2005 and 2004, the Company used exchange rates of 3.03 pesos to \$1 and 2.98 pesos to \$1, respectively, to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries. The remeasurement of the peso-denominated monetary net assets of the Company's Argentine subsidiaries as of December 31, 2005, 2004 and 2003 resulted in gains of $.2 million and $.2 million and a charge of $.3 million, respectively.

As a result of certain Argentine stability laws and regulations enacted since the devaluation of the Argentine peso that impact the price the Company receives for the oil and gas it produces, the Company continually reviews its Argentine proved and unproved properties for impairment. Based on (i) the Company's announced sales price for its Argentine assets, as more fully discussed in Note W and (ii) estimates of future commodity prices and operating costs, the Company believes that the future cash flows from its Argentine oil and gas assets will be sufficient to fully recover its proved property basis. Based upon the announced sales price for the Argentine assets, the Company does not believe it has an impairment of its unproved properties. If the sale is unsuccessful, the Company intends to continue its exploration efforts on all of its remaining unproved acreage. Based upon the Company's improved economic outlook for Argentina during 2005, the Company increased its capital budget for exploration and development activities in 2005 as compared to the capital budgets in 2004 and 2003.

While the Argentine economic and political situation continues to improve, 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, (iv) the Company's level of future investments in Argentina and (v) peso-denominated monetary assets and liabilities. While conditions are improving, numerous uncertainties exist surrounding the ultimate resolution of Argentina's economic and political stability.

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

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

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

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company had no investments in available-for-sale securities as of December 31, 2005 or 2004.

Investments in unaffiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company had no significant equity security investments that did not have a readily determinable fair value as of December 31, 2005 or 2004.

Inventories. Inventories were comprised of $77.3 million and $37.9 million of materials and supplies and $2.4 million and $2.4 million of commodities as of December 31, 2005 and 2004, respectively. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a first-in, first-out basis. Commodities inventory is carried at the lower of average cost or market, on a first-in, first-out basis. As of December 31, 2005 and 2004, the Company's materials and supplies inventory was net of $.2 million and $.4 million, respectively, of valuation reserve allowances.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use.

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

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

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

Due to the capital intensive nature and the geographical location of certain Alaskan, deepwater Gulf of Mexico and foreign projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is impaired. See Note D for additional information regarding the Company's suspended exploratory well cost and "New accounting pronouncements" below for information regarding the Company's adoption of Financial Accounting Standards Board ("FASB") Staff Position No. FAS 19-1, "Accounting for Suspended Well Costs" ("FSP FAS 19-1").

The Company owns interests in 12 natural gas processing plants and three treating facilities. The Company operates eight of the plants and all three treating facilities. The Company's ownership interests in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. The third party revenues generated from the plant and treating facilities for the three years ended December 31, 2005, 2004 and 2003 were $58.1 million, $45.9 million and $39.5 million, respectively. The third party expenses attributable to the plants and treating facilities for the same respective periods were $18.0 million, $11.9 million and $11.3 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

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

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

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"), the Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved oil and gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time by recording an allowance.

Goodwill. As described in Note C, the Company recorded $327.8 million of goodwill associated with the Evergreen merger. The goodwill was recorded to the Company's United States reporting unit. In accordance with EITF Abstract Issue No. 00-23, "Issues Related to the Accounting for Stock Compensation under APB Opinion No. 25 and FASB Interpretation No. 44", the Company has reduced goodwill by $16.2 million since September 28, 2004 for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the Evergreen merger. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", goodwill is not amortized to earnings, but is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. If the carrying value of goodwill is determined to be impaired, it is reduced for the impaired value with a corresponding charge to pretax earnings in the period in which it is determined to be impaired. During the third quarter of 2005, the Company performed its annual assessment of impairment of the goodwill and determined that there was no impairment.

Other property, plant and equipment, net. Other property, plant and equipment is stated at cost and primarily consists of items such as heavy equipment and rigs, furniture and fixtures and leasehold improvements. Depreciation is provided over the estimated useful life of the assets using the straight-line method. At December 31, 2005 and 2004, other property, plant and equipment was net of accumulated depreciation of $131.5 million and $112.3 million, respectively.

Asset retirement obligations. The Company accounts for asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), which was adopted by the Company on January 1, 2003. SFAS 143 amended SFAS 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.

As a result of the adoption of SFAS 143, on January 1, 2003 the Company recorded a cumulative effect adjustment gain of $15.4 million, net of $1.3 million of deferred tax, as a cumulative effect adjustment of a change in accounting principle in the Company's Consolidated Statements of Operations. See Note L for additional information regarding the Company's asset retirement obligations.

The following table illustrates the pro forma effect on net income and earnings per share for the year ended December 31, 2003 as if the Company had adopted the provisions of SFAS 143 on January 1, 2003 (in thousands, except per share amounts).

Net income, as reported	$410,592
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(15,413)
Pro forma net income	$395,179
Net income per share:	
Basic — as reported	$ 3.50
Basic — pro forma	$ 3.37
Diluted — as reported	$ 3.46
Diluted — pro forma	$ 3.33

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143" ("FIN 47"). FIN 47 clarifies that conditional asset retirement obligations meet the definition of liabilities and should be recognized when incurred if their fair values can be reasonably estimated. The interpretation was adopted by the Company on December 31, 2005. The adoption of FIN 47 had no impact on the Company's financial position or results of operations.

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

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

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

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

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

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

The Company uses the entitlements method of accounting for oil, natural gas liquid ("NGL") and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying Consolidated Balance Sheets.

The Company had no material oil or NGL entitlement assets or liabilities as of December 31, 2005 or 2004. The following table presents the Company's gas entitlement assets and liabilities and their associated volumes as of December 31, 2005 and 2004:

	December 31,			
	2005		2004	
	Amount	MMcf	Amount	MMcf
	($ in millions)			
Entitlement assets	$12.1	4,007	$10.4	3,842
Entitlement liabilities	$ 8.5	7,206	$14.7	11,859

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 H. The Company accounts for stock-based compensation granted under the Long-Term Incentive Plan using the intrinsic value method prescribed by Accounting Principles Bulletin Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") and related interpretations. Stock-based compensation expense associated with option grants was not recognized in the determination of the Company's net income during the years ended December 31, 2005, 2004 and 2003, 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 or were issued in exchange for fully-vested Evergreen options as purchase consideration in the Evergreen merger. Stock-based compensation expense associated with restricted stock awards is deferred and amortized to earnings ratably over the vesting periods of the awards. See "New accounting pronouncements" below for information regarding the Company's adoption of SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") on January 1, 2006.

The following table illustrates the pro forma effect on net income and net income per share as if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), to stock-based compensation during the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Net income, as reported	$534,568	$312,854	$410,592
Plus: Stock-based compensation expense included in net income for all awards, net of tax(a)	17,054	7,939	3,447
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of tax(a)	(19,772)	(13,985)	(11,429)
Pro forma net income	$531,850	$306,808	$402,610
Net income per share:			
Basic — as reported	$ 3.90	$ 2.50	$ 3.50
Basic — pro forma	$ 3.88	$ 2.45	$ 3.44
Diluted — as reported	$ 3.80	$ 2.46	$ 3.46
Diluted — pro forma	$ 3.78	$ 2.41	$ 3.40

(a) For the years ended December 31, 2005, 2004 and 2003, stock-based compensation expense included in net income is net of tax benefits of $9.8 million, $4.6 million and $2.0 million, respectively. Similarly, stock-based compensation expense determined under the fair value based method for the years ended December 31, 2005, 2004 and 2003 is net of tax benefits of $11.4 million, $8.0 million and $6.6 million, respectively. See Note P for additional information regarding the Company's income taxes.

Foreign currency translation. The U.S. dollar is the functional currency for all of the Company's 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. Nonmonetary assets and liabilities denominated in a foreign currency are remeasured at the historic exchange rates that were in effect when the assets or liabilities were acquired or incurred.

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) — cumulative translation adjustment.

The following table presents the exchange rates used to translate the financial statements of the Company's Canadian subsidiaries in the preparation of the consolidated financial statements as of and for the years ended December 31, 2005, 2004 and 2003:

	December 31,		
	2005	2004	2003
U.S. Dollar from Canadian Dollar — Balance Sheets	.8606	.8320	.7710
U.S. Dollar from Canadian Dollar — Statements of Operations	.8279	.7699	.7161

Reclassifications. Certain reclassifications have been made to the 2004 and 2003 amounts in order to conform with the 2005 presentation. Specifically, the Company reduced cash used for additions to oil and gas properties included in investing activities and the add-back of exploration expenses in operating activities in the accompanying Consolidated Statements of Cash Flows by approximately $53.0 million and $25.6 million for the years ended December 31, 2004 and 2003, respectively, representing reclassifications of geological expenses incurred in the related periods.

New accounting pronouncements. The following discussions provide information about new accounting pronouncements that have been issued by the FASB:

SFAS 123(R). In December 2004, the FASB issued SFAS 123(R), which is a revision of SFAS 123. SFAS 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows". Generally, the approach in SFAS 123(R) is similar to the approach described in SFAS 123. However, SFAS 123(R) will require all share-based payments to employees, including grants of employee stock options, to be recognized as stock-based compensation expense in the Company's Consolidated Statements of Operations based on their fair values. Pro forma disclosure is no longer an alternative.

SFAS 123(R) must be adopted no later than January 1, 2006 and permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123(R) for all share-based payments granted after the adoption date and based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the adoption date.
- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

The Company adopted the provisions of SFAS 123(R) on January 1, 2006 using the modified prospective method.

As permitted by SFAS 123, the Company accounted for share-based payments to employees prior to January 1, 2006 using the intrinsic value method prescribed by APB 25 and related interpretations. As such, the Company generally did not recognize compensation expense associated with employee stock option grants. The Company has not issued stock options to employees since 2003. Consequently, the adoption of SFAS 123(R)'s fair value method will not have a significant impact on the Company's future results of operations or financial position. Had the Company adopted SFAS 123(R) in prior periods, the impact would have approximated the impact of SFAS 123 as described in the pro forma disclosures above. The adoption of SFAS 123(R) will have no effect on future results of operations related to the Company's unvested outstanding restricted stock awards. The Company estimates that the adoption of SFAS 123(R), based on estimated outstanding unvested stock options, will result in compensation charges of approximately $1.0 million during 2006.

The Company has an Employee Stock Purchase Plan (the "ESPP") that allows eligible employees to annually purchase the Company's common stock at a discount. The provisions of SFAS 123(R) will cause the ESPP to be a compensatory plan. However, the change in accounting for the ESPP is not expected to have a material impact on the Company's financial position, future results of operations or liquidity. Historically, the ESPP compensatory amounts have been nominal. See Note H for additional information regarding the ESPP.

SFAS 123(R) also requires that tax benefits in excess of recognized compensation expenses be reported as a financing cash flow, rather than an operating cash flow as required under prior literature. This requirement may serve to reduce the Company's future cash flows from operating activities and increase future cash flows from financing activities, to the extent of associated tax benefits that may be realized in the future.

FSP FAS 19-1. In April 2005, the FASB issued FSP FAS 19-1. FSP FAS 19-1 amended SFAS 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19-1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the second quarter of 2005. See Note D for additional information regarding the Company's exploratory well costs. The adoption of FSP FAS 19-1 did not impact the Company's consolidated financial position or results of operations.

NOTE C. Acquisitions

Evergreen merger. On September 28, 2004, Pioneer completed a merger with Evergreen, with Pioneer being the surviving corporation for accounting purposes. The transaction was accounted for as a purchase of Evergreen by Pioneer. The merger with Evergreen was accomplished through the issuance of 25.4 million shares of Pioneer common stock and $851.1 million of cash paid to Evergreen shareholders at closing, net of $12.1 million of acquired cash. The cash consideration paid in the merger was financed through borrowings on the Company's unsecured revolving credit facilities. See Note F for additional information regarding the credit facilities.

The Company recorded $327.8 million of goodwill associated with the Evergreen merger, which represented the excess of the purchase consideration over the net fair value of the identifiable net assets acquired.

The following unaudited pro forma combined condensed financial data for the years ended December 31, 2004 and 2003 were derived from the historical financial statements of Pioneer and Evergreen giving effect to the merger as if the merger had occurred on January 1, 2003. The unaudited pro forma combined condensed financial data have been included for comparative purposes only, are not necessarily indicative of the results that might have occurred had the merger taken place on January 1, 2003 and are not intended to be a projection of future results.

	Year Ended December 31, 2004	Year Ended December 31, 2003
	(In thousands, except per share amounts)	
Revenues	$1,964,549	$1,441,933
Income from continuing operations before cumulative effect of change in accounting principle	$ 308,829	$ 397,776
Income from discontinued operations, net of tax	13,925	17,382
Cumulative effect of change in accounting principle, net of tax	—	15,036
Net income	$ 322,754	$ 430,194
Basic earnings per share:		
Income from continuing operations before cumulative effect of change in accounting principle	$ 2.14	$ 2.79
Income from discontinued operations, net of tax	.10	.12
Cumulative effect of change in accounting principle, net of tax	—	.11
Net income	$ 2.24	$ 3.02
Diluted earnings per share:		
Income from continuing operations before cumulative effect of change in accounting principle	$ 2.08	$ 2.71
Income from discontinued operations, net of tax	.10	.12
Cumulative effect of change in accounting principle, net of tax	—	.10
Net income	$ 2.18	$ 2.93

Permian Basin and Gulf Coast acquisitions. During 2005, the Company spent $176.9 million to acquire various working interests in the Spraberry and South Texas areas, including the assumption of approximately $3.0 million in asset retirement obligations.

Falcon acquisitions. During March 2003, the Company purchased the remaining 25 percent working interest that it did not already own in the Falcon field, the Harrier field and surrounding satellite prospects in the deepwater Gulf of Mexico for $120.4 million, including $114.1 million of cash, $1.7 million of asset retirement obligations assumed and $4.6 million of closing adjustments.

NOTE D. Exploratory Well Costs

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

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Beginning capitalized exploratory well costs	$126,472	$108,986	$ 71,500
Additions to exploratory well costs pending the determination of proved reserves	243,272	156,937	216,352
Reclassifications due to determination of proved reserves	(78,334)	(56,639)	(117,966)
Exploratory well costs charged to expense	(93,119)	(82,812)	(60,900)
Ending capitalized exploratory well costs	$198,291	$126,472	$ 108,986

The following table provides an aging as of December 31, 2005, 2004 and 2003 of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the date the drilling was completed:

	December 31,		
	2005	2004	2003
	(In thousands, except well counts)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 84,042	$ 35,046	$ 75,120
Capitalized exploratory well costs that have been capitalized for a period greater than one year	114,249	91,426	33,866
	$198,291	$126,472	$ 108,986
Number of wells with exploratory well costs that have been capitalized for a period greater than one year	14	10	3

The following table provides the capitalized costs of exploration projects that have been suspended for more than one year as of December 31, 2005, 2004 and 2003:

	December 31,		
	2005	2004	2003
		(In thousands)	
United States:			
Ozona Deep	$ 19,423	$ 19,462	$ 19,003
Oooguruk	52,205	47,083	—
Thunder Hawk	25,769	—	—
Canada — other	805	1,214	—
South Africa	7,227	14,895	14,863
Tunisia — Anaguid	8,820	8,772	—
Total	$114,249	$ 91,426	$ 33,866

The following discussion describes the history and status of each significant suspended exploratory project:

Ozona Deep. The Company's Ozona Deep exploration well was drilled during 2002 and found quantities of oil believed to be commercial; however, given its location in the Gulf of Mexico, it is necessary to have a signed production handling agreement ("PHA") with infrastructure in the area to insure the economics associated with the discovery prior to doing further appraisal drilling. During the third quarter of 2005, Pioneer and the operator of Ozona Deep signed a Capacity Commitment Agreement with a third party platform to bring future production from the discovery to the third party's platform. The Company anticipates entering into a PHA in 2006 and drilling an appraisal well during 2006.

Oooguruk. During 2003, the Company's Alaskan Oooguruk discovery wells found quantities of oil believed to be commercial. In 2003, the Company began farm-in discussions with the owner of undeveloped discoveries in adjacent acreage given its proximity and the potential cost benefits of a larger scale project. The farm-in was completed during 2004. Along with completing the farm-in agreement, Pioneer obtained access to exploration well and seismic data to improve the Company's understanding of the potential of the discoveries without having to drill additional wells. In late 2004, the Company completed an extensive technical and economic evaluation of the resource potential within this area and authorized a front-end engineering design study ("FEED study") for the area which was completed.

During the first quarter of 2006, the Company sanctioned the development of the discovery and obtained the necessary regulatory approvals. The Company will begin operations to install an offshore gravel drilling and production site in order to complete gravel hauling activities during the 2006 winter construction season. Following construction of the gravel drilling and production site, a subsea flowline and facilities will be installed during 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit. Pioneer plans to drill approximately 40 horizontal wells to develop the discovery. Depending on weather conditions and facilities completion and accessibility, drilling could begin as early as the fall of 2007.

Thunder Hawk. During 2004, the Company's initial Thunder Hawk well found quantities of oil believed to be commercial. Additional appraisal wells were determined necessary to confirm the commercialization of the discovery. In the fourth quarter of 2005, the third appraisal well was spudded and plans to complete the drilling of the previously spudded second well, which was temporarily suspended due to weather. Completion of the drilling is expected in the first half of 2006.

South Africa. During 2001, the Company drilled two South African discovery wells that found quantities of gas and condensate believed to be commercial. During 2004, 2003 and 2002, the Company actively reviewed the gas supply and demand fundamentals in South Africa and had discussions with a gas-to-liquids ("GTL") plant in the area to purchase the condensate and gas. During 2004, a FEED study was authorized for the gas development and infrastructure design. The FEED study was completed in early 2005 and based on that study, the GTL plant operator initiated purchase orders for long-lead time infrastructure components. In December 2005, the Company announced the final approvals with its partner in the South Coast gas project to commence the initial development of the project. The project will include subsea tie-back of gas from the Sable field and six additional gas accumulations to the existing production facilities on the F-A platform for transportation via existing pipelines to the GTL plant. Production is expected to begin during the second half of 2007. Additional development drilling related to the project is expected to commence in the first quarter of 2006. As a result, the Company added 11.4 MBOE of reserves in 2005 and reduced the suspended exploratory costs by approximately $6.2 million.

At December 31, 2005, the remaining costs associated with this project relate to the Boomslang discovery, which was not included in the initial development of this project. Boomslang is both an oil and gas discovery. Continued studies of the commercialization of the project are ongoing. Part of the ongoing efforts is determining the commercialization of the discovery as an oil project, gas project or both. If commercialized as an oil discovery, earliest production would be 2009 and if commercialized as a gas discovery, earliest production would be 2012.

Tunisia — Anaguid. During 2003, the Company drilled two exploration wells on its Anaguid Block in Tunisia which found quantities of condensate and gas believed to be commercial. During 2004, the wells were scheduled and approved for extended production tests. However, the project operator delayed the extended production tests due to issues unrelated to the Company or the project. In the third quarter of 2005, the project operator, along with the Company, conducted an extended production test of one of the two existing exploration wells and drilled an offset appraisal well to the other exploration well.

The results of the extended production test were unfavorable and the Company expensed the costs associated with this well in the third quarter of 2005, which were approximately $5.1 million. However, the appraisal well offsetting the second discovery encountered gas and condensate in a similar horizon to the initial well. The Company is currently reviewing data from the appraisal well to determine whether development of the area is economical.

NOTE E. Disclosures About Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2005 and 2004:

	December 31,			
	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Net derivative contract liabilities:				
Commodity price hedges	$(748,477)	$(748,477)	$(406,546)	$(406,546)
Unrealized terminated commodity price hedges	$ (870)	$ (870)	$ (660)	$ (660)
Financial assets:				
Trading securities	$ 15,237	$ 15,237	$ 11,115	$ 11,115
5½% note receivable due 2008	$ 1,429	$ 1,429	$ 1,786	$ 1,786
Financial liabilities — long-term debt:				
Line of credit	$(900,000)	$(900,000)	$(828,000)	$(828,000)
8⅞% senior notes due 2005	$ —	$ —	$(131,762)	$(133,078)
8¼% senior notes due 2007	$ (32,199)	$ (33,477)	$ (32,520)	$ (35,465)
6½% senior notes due 2008	$(348,714)	$(356,965)	$(350,326)	$(374,500)
9⅝% senior notes due 2010	$ —	$ —	$ (62,973)	$ (78,672)
5⅞% senior notes due 2012	$ (6,255)	$ (5,947)	$(199,687)	$(203,198)
7½% senior notes due 2012	$ —	$ —	$ (15,157)	$ (18,621)
5⅞% senior notes due 2016	$(421,327)	$(506,590)	$(415,609)	$(549,478)
4¾% senior convertible notes due 2021(a)	$(100,000)	$(201,225)	$(100,000)	$(165,598)
7⅕% senior notes due 2028	$(249,917)	$(265,200)	$(249,916)	$(287,500)

(a) Carrying value excludes $63.5 million which was recognized in additional paid-in capital in conjunction with the Evergreen merger for the fair value of the convertible debt attributable to the equity conversion rights. See Note C for information regarding the Evergreen merger.

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

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

Financial assets. The carrying amounts of the trading securities approximates fair value due to the short maturity of these instruments. The fair value of the 5½ percent note receivable due 2008 (the "5½% Note") was determined based on underlying market rates of interest. The current portion of the 5½% Note, amounting to $.4 million as of December 31, 2005 and 2004, is included in other current assets, net in the Company's Consolidated Balance Sheets. The trading securities and the noncurrent portions of the 5½% Note are included in other assets, net in the Company's Consolidated Balance Sheets.

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 F for additional information regarding the Company's long-term debt.

NOTE F. Long-term Debt

Long-term debt, including the effects of net deferred fair value hedges losses and issuance discounts and premiums, consisted of the following components at December 31, 2005 and 2004:

	December 31,	
	2005	2004
	(In thousands)	
Outstanding debt principal balances:		
Lines of credit	$ 900,000	$ 828,000
8⅞% senior notes due 2005	—	130,950
8¼% senior notes due 2007	32,075	32,075
6½% senior notes due 2008	350,000	350,000
9⅝% senior notes due 2010	—	64,044
5⅞% senior notes due 2012	6,110	194,485
7½% senior notes due 2012	—	16,175
5⅞% senior notes due 2016	526,875	526,875
4¾% senior convertible notes due 2021	100,000	100,000
7⅕% senior notes due 2028	250,000	250,000
	2,165,060	2,492,604
Issuance discounts and premiums, net	(102,347)	(103,170)
Net deferred fair value hedge losses	(4,301)	(3,484)
Total long-term debt	$2,058,412	$2,385,950

Lines of credit. During September 2005, the Company entered into an Amended and Restated 5-Year Revolving Credit Agreement (the "Amended Credit Agreement") that amended the Company's $700 million 5-Year Revolving Credit Agreement. In connection with funding of the Amended Credit Agreement, all amounts outstanding under a 364-day credit facility, which was established to fund the Evergreen merger in September 2004, were retired and the 364-day credit facility terminated. The Amended Credit Agreement matures in September 2010 unless extended in accordance with the terms of the Amended Credit Agreement. The terms of the Amended Credit Agreement provide for initial aggregate loan commitments of $1.5 billion, which may be increased to a maximum aggregate amount of $1.8 billion if the lenders increase their loan commitments or if loan commitments of new financial institutions are added to the Amended Credit Agreement.

Borrowings under the Amended Credit Agreement may be in the form of revolving loans or swing line loans. Aggregate outstanding swing line loans may not exceed $100 million. Revolving loans bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank (7.25 percent per annum at December 31, 2005) or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day (4.09 percent per annum at December 31, 2005) plus .5 percent or (b) a base Eurodollar rate, substantially equal to LIBOR (4.84 percent per annum at December 31, 2005), plus a margin (the “Applicable Margin”) that is determined by reference to a grid based on the Company’s debt rating (.75 percent per annum at December 31, 2005). The Applicable Margin is increased by .10 percent to .125 percent per annum, depending on the Company’s debt ratings, if total borrowings under the Amended Credit Agreement exceed 50 percent of the aggregate loan commitments. Swing line loans bear interest at a rate per annum equal to the “ASK” rate for Federal funds periodically published by the Dow Jones Market Service plus the Applicable Margin. The Company pays commitment fees on the undrawn amounts under the Amended Credit Agreement that are determined by reference to a grid based on the Company’s debt rating (.125 percent per annum at December 31, 2005).

As of December 31, 2005, the Company had $87.8 million of undrawn letters of credit, of which $80.3 million were undrawn commitments under the Amended Credit Agreement. The letters of credit outstanding under the Amended Credit Agreement are subject to a per annum fee, based on a grid of the Company’s debt rating, representing the Company’s LIBOR margin (4.84 percent at December 31, 2005) plus .75 percent. As of December 31, 2005, the Company had unused borrowing capacity of $519.7 million under the Amended Credit Agreement.

In January 2006, Moody’s Investor Services, Inc. (“Moody’s”) downgraded the Company from Baa3 to Ba1. The downgrade triggered changes in the pricing grid under the Amended Credit Agreement. The Applicable Margin and the spread on the letters of credit increased from .75 percent to 1.00 percent.

The Amended Credit Agreement contains certain financial covenants, which include the (i) maintenance of a ratio of the Company’s earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonments expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; (ii) maintenance of a ratio of total debt to book capitalization less intangible assets, accumulated other comprehensive income and certain noncash asset impairments not to exceed .60 to 1.0; and (iii) because the Company fell below an investment grade rating by both Moody’s and Standard & Poor’s Ratings Group, Inc. prior to attaining a mid-investment grade rating (as defined in the Amended Credit Agreement) by either of such rating agencies, then such covenants also include the maintenance of an annual ratio of the net present value of the Company’s oil and gas properties to total debt of at least 1.50 to 1.0 for the first 18 months following the date of the Amended Credit Agreement, and 1.75 to 1.0 thereafter. The lenders may declare any outstanding obligations under the Amended Credit Agreement immediately due and payable upon the occurrence, and during the continuance of, an event of default, which includes a defined change in control of the Company. As of December 31, 2005, the Company was in compliance with all of its debt covenants.

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 are structurally subordinated to all obligations of its subsidiaries. Interest on the Company’s senior notes is payable semiannually.

Senior convertible notes. The $100 million of 4¾% senior convertible notes due 2021 (the "Convertible Notes") are convertible at the option of the holders. If the holders of the Convertible Notes do not redeem the Convertible Notes prior to December 20, 2006 (the Company's first redemption right) the Company currently intends to exercise its rights under the indenture and redeem the Convertible Notes on such date for cash, common stock or a combination thereof. If the holders do not exercise their rights to convert the Convertible Notes prior to December 20, 2006, the Company intends to refinance the cash redemption costs with unused borrowing capacity under the Amended Credit Agreement. The Convertible Notes are reflected in "Thereafter" in the below maturities table. Accordingly, the Company has classified the Convertible Notes as long-term in its Consolidated Balance Sheet as of December 31, 2005.

Each $25.00 principal balance outstanding under the Convertible Notes is convertible into .58175 shares of the Company's common stock plus $19.98 per share, which includes Evergreen Kansas properties proceeds (as an example, each $1,000 of Convertible Notes principal would exchange for 23.27 shares of the Company's common stock plus $799.20 of cash). The portion of the Convertible Notes exchangeable into the Company's common stock is included in the computation of the Company's average diluted shares outstanding.

Early extinguishment of debt. During 2005, the Company (i) redeemed the remaining principal amounts of its outstanding 9⅝% senior notes due 2010 (the "9⅝% Notes") and its 7½% senior notes due 2012 (the "7.50% Notes") of $64.0 million and $16.2, respectively, and (ii) accepted tenders to purchase for cash $188.4 million in principal amount of its 5⅞% senior notes due 2012 (the "5⅞% Notes"). Consequently, the Company recognized a charge for the early extinguishment of debt of $26.5 million included in other expense in the accompanying Consolidated Statements of Operations on these redemptions and tenders for 2005.

In addition, the Company received sufficient consents from the holders of the 5⅞% Notes to permanently remove substantially all of the operating restrictions contained in the indenture governing the 5⅞% Notes.

In conjunction with the 2004 Change of Control Offer provided as a result of the merger with Evergreen, the Company repurchased $5.5 million of the 5⅞% Notes during 2004. The Company recognized $.1 million of other income associated with these debt extinguishments.

During 2003, the Company repurchased $5.1 million of its 8⅞ percent senior notes and repaid its former revolving credit agreement prior to its scheduled maturity. The Company recognized $1.5 million of charges to other expense associated with these debt extinguishments.

Principal maturities. Principal maturities of long-term debt at December 31, 2005 are as follows (in thousands):

2006	$ —
2007	$ 32,075
2008	$350,000
2009	$ —
2010	$900,000
Thereafter	$882,985

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Cash payments for interest	$129,875	$110,135	$117,870
Accretion/amortization of discounts or premiums on loans	6,186	3,683	2,873
Amortization of net deferred hedge gains (see Note J)	(4,052)	(19,220)	(26,114)
Amortization of capitalized loan fees	2,265	2,059	2,528
Kansas ad valorem tax (see Note I)	—	65	103
Argentina accrued tax liability (see Note P)	1,694	1,205	—
Net change in accruals	(7,092)	7,476	(424)
Interest incurred	128,876	105,403	96,836
Less capitalized interest	(1,089)	(2,016)	(5,448)
Total interest expense	$127,787	$103,387	$ 91,388

NOTE G. Related Party Transactions

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

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$1,493	$1,458	$1,473
Reimbursement of general and administrative expenses	$ 348	$ 193	$ 148

NOTE H. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors (the "Board") approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first 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 $1.2 million, $.9 million and $.9 million for the years ended December 31, 2005, 2004 and 2003, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. ("Pioneer USA") 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount of not less than two percent nor more than 30 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's base compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, 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, 2005, 2004 and 2003, the Company recognized compensation expense of \$8.0 million, \$5.4 million and \$4.5 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In August 1997, the Company's stockholders approved a 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 ten 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, 2005 and 2004:

	December 31,	
	2005	2004
Shares outstanding, net of treasury stock	128,588,364	144,831,662
Outstanding awards exercisable or exercisable within 60 days	2,607,485	4,526,415
	131,195,849	149,358,077
Maximum shares/options allowed under the Long-Term Incentive Plan	13,119,585	14,935,808
Less: Outstanding awards under the Long-Term Incentive Plan	(3,836,958)	(4,790,028)
Outstanding awards under predecessor incentive plans	(814,663)	(1,838,543)
Shares/options available for future grant	8,467,964	8,307,237

Stock option awards. Prior to 2004, the Company had a program of awarding semiannual stock options to its employees. The Company granted 1,353,988 options under the Long-Term Incentive Plan during 2003.

In accordance with the Evergreen merger agreement, on September 28, 2004, the Company assumed fully-vested options to purchase 2,384,657 shares of the Company's common stock at various exercise prices, the weighted average price per share of which was \$11.18. The assumed options were outstanding awards to Evergreen employees when the Evergreen merger occurred.

During 2004, the Company's stock-based compensation philosophy shifted its emphasis from the awarding of stock options to restricted stock awards. There were no options granted under the Long-Term Incentive Plan during 2005 or 2004.

Restricted stock awards. During 2005, the Company issued 1,411,269 restricted shares of the Company's common stock as compensation to directors, officers and employees of the Company.

During 2004, the Company assumed 214,186 restricted stock units in exchange for Evergreen restricted stock units outstanding on September 28, 2004 and issued 630,937 restricted shares of the Company's common stock as compensation to directors, officers and employees of the Company. The Company recorded $6.0 million of deferred compensation for future expected service associated with certain of the restricted stock units assumed from Evergreen. The deferred compensation is being amortized as charges to compensation expense over the periods in which the restrictions on the units lapse.

For the 2005-2006 director year, the Company's non-employee directors were offered a choice to receive their annual fee retainers (i) 100 percent in restricted stock units, (ii) 100 percent in cash or (iii) a combination of 50/50 of cash and restricted stock units. All non-employee directors also received an annual equity grant of restricted stock units.

During 2003, the Company issued 77,625 restricted shares of the Company's common stock. The restricted share awards were issued as compensation to directors, officers and key employees of the Company.

The Company recorded $56.2 million, $19.1 million and $1.1 million of deferred compensation associated with restricted stock awards in stockholders' equity during 2005, 2004 and 2003, respectively. Such amounts will be amortized to compensation expense over the vesting periods of the awards. During 2005, 2004 and 2003, amortization of restricted stock awards of $26.9 million, $12.5 million and $5.4 million, respectively, was recognized as compensation expense.

The following table reflects the outstanding restricted stock awards as of December 31, 2005, 2004 and 2003 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2005		2004		2003	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Restricted stock awards:						
Outstanding at beginning of year	1,447,987	$28.46	676,973	$24.79	652,793	$24.72
Evergreen awards assumed	—	$ —	214,186	$32.58	—	$ —
Shares granted	1,411,269	$39.79	630,937	$31.29	77,625	$25.39
Shares forfeited	(174,046)	$33.99	(32,174)	$30.99	(36,500)	$24.72
Lapse of restrictions	(718,987)	$26.26	(41,935)	$31.09	(16,945)	$24.69
Outstanding at end of year	1,966,223	$36.90	1,447,987	$28.46	676,973	$24.79

A summary of the Company's stock option plans as of December 31, 2005, 2004 and 2003, and changes during the years then ended, are presented below:

	Year Ended December 31,					
	2005		2004		2003	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Non-statutory stock options:						
Outstanding at beginning of year	5,180,584	$18.60	5,274,116	$20.13	7,268,292	$19.60
Evergreen options assumed	—	$ —	2,384,657	$11.18	—	$ —
Options granted	—	$ —	—	$ —	1,353,988	$24.84
Options forfeited	(65,190)	$22.94	(102,890)	$22.24	(1,286,370)	$29.22
Options exercised	(2,429,996)	$15.95	(2,375,299)	$14.39	(2,061,794)	$15.68
Outstanding at end of year	2,685,398	$20.32	5,180,584	$18.60	5,274,116	$20.13
Exercisable at end of year	2,382,714	$19.74	3,970,996	$17.08	2,581,256	$17.56
Weighted average fair value of options granted during the year	$ —(a)		$ —(a)		$ 8.95	

(a) The Company did not grant any stock options under the Long-Term Incentive Plan during 2005 or 2004.

The following table summarizes information about the Company's stock options outstanding and options exercisable at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2005	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2005	Weighted Average Exercise Price
$5-$11	211,286	2.5 years	$ 9.73	211,286	$ 9.73
$12-$18	1,049,191	2.7 years	$16.96	1,049,191	$16.96
$19-$26	1,339,137	3.3 years	$23.94	1,036,453	$23.68
$27-$30	67,928	.7 years	$28.44	67,928	$28.44
$31-$43	17,856	1.1 years	$40.23	17,856	$40.23
	2,685,398			2,382,714	

SFAS 123 disclosures. The Company applied 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 earnings per share would have been less than the reported amounts.

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. The Company did not grant any stock options during the years ended December 31, 2005 or 2004. The following weighted average assumptions were used to estimate the fair value of options granted during the year ended December 31, 2003:

Risk-free interest rate	3.06%
Expected life	5 years
Expected volatility	36%
Expected dividend yield	—

Employee Stock Purchase Plan

As discussed above in Note B, the Company has an ESPP that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the 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 offering period, whichever closing sales price is lower.

Postretirement Benefit Obligations

As of December 31, 2005 and 2004, the Company had recorded $18.6 million and $15.5 million, respectively, of unfunded accumulated postretirement benefit obligations, the current and noncurrent portions of which are included in other current liabilities and other liabilities and minority interests, respectively, in the accompanying Consolidated Balance Sheets. These obligations are comprised of five plans of which four relate to predecessor entities that the Company acquired in prior years. These plans had no assets as of December 31, 2005 or 2004. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

As of December 31, 2005, the accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $14.4 million of unfunded accumulated postretirement benefit obligations and by the Company for one plan representing $4.2 million of unfunded accumulated postretirement benefit obligations. Interest costs at an annual rate of 5.75 percent of the periodic undiscounted accumulated postretirement benefit obligations were employed in the valuations of the benefit obligations. Certain of the aforementioned plans provide for medical and dental cost subsidies for plan participants. Annual medical cost escalation trends of 10.0 percent in 2006, declining to 5.0 percent in 2011 and thereafter, and annual dental cost escalation trends of 6.5 percent in 2006, declining to 5.0 percent in 2009 and thereafter, were employed to estimate the accumulated postretirement benefit obligations associated with the medical and dental cost subsidies.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Beginning accumulated postretirement benefit obligations	$15,534	$15,556	$19,743
Net benefit payments	(1,393)	(1,497)	(1,472)
Service costs	324	258	205
Net actuarial losses (gains)	3,211	(32)	(4,410)
Accretion of discounts	900	909	1,490
Fair value of Evergreen obligations assumed	—	340	—
Ending accumulated postretirement benefit obligations	$18,576	$15,534	$15,556

Estimated benefit payments and service/interest costs associated with the plans for the year ending December 31, 2006 are $1.5 million and $1.9 million, respectively.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers, subsidiary company officers and certain key employees. Salaries and bonuses for the Company's officers are set by the Board for the parent company officers and by the Company's management committee for subsidiary company officers and key employees. The Board and management committee 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 $33.2 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 the legal proceedings that are described below. The Company is also party to other proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect its assessment of 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 and the case now contains two material claims. First, the plaintiffs assert that they were improperly charged expenses (primarily field compression), which plaintiffs allege are a "cost of production", and for which the plaintiffs claim they, as royalty owners, are not responsible. Second, the plaintiffs claim they are entitled to 50 percent 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 (both for periods covered by the lawsuit and from the last date covered by the lawsuit to the present — because the deductions continue to be taken and the plaintiffs continue to be paid for a royalty share of the helium) could reach approximately $35 million related to the cost of production claim and approximately $18 million to $43 million related to the helium claim, plus prejudgment interest. However, the Company believes it has valid defenses to the plaintiffs' claims and has paid the plaintiffs properly under their respective oil and gas leases and other agreements, and intends to vigorously defend itself.

The Company does not believe the costs it has deducted are a "cost of production". The costs being deducted are post production costs incurred to transport the gas to the Company's Satanta gas plant for processing, where the 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 and with the parties' agreements.

The Company has also vigorously defended against plaintiffs' claims for 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. In more recent filings with the court, plaintiffs asserted that an equal division between Pioneer and its royalty owners of the proceeds from helium would provide the most equitable result. The Company has not established a provision for the helium claim.

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 the plaintiffs and believes it presented strong evidence at trial to support its positions. However, either through a negotiated settlement or court ruling, the Company could have to pay some part of the cost of production claim and, accordingly, the Company has established a partial reserve for this claim. Although the amount of any resulting liability, to the extent that it exceeds the Company's provision, 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 additional 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.

MOSH Holding. The Company and its principal United States subsidiary, Pioneer USA, were named as defendants in *MOSH Holding, L.P. v Pioneer Natural Resources Company; Pioneer Natural Resources USA, Inc.; Woodside Energy (USA) Inc.; and JPMorgan Chase Bank, NA, as Trustee of the Mesa Offshore Trust*, which was filed on April 11, 2005, in the District Court of Travis County, Texas (250th Judicial District). The plaintiff is a unitholder in the Mesa Offshore Trust, which was created in 1982 as the sole limited partner in a partnership that holds an overriding royalty interest in certain oil and gas leases offshore Louisiana and Texas. The plaintiff alleges that the Company, together with Woodside Energy (USA) Inc. ("Woodside"), concealed the value of the royalty interest and worked to terminate the Mesa Offshore Trust prematurely and to capture for itself and Woodside profits that belong to the Mesa Offshore Trust. The plaintiff also alleges breaches of fiduciary duty, misapplication of trust property, common law fraud, gross negligence, and breach of the conveyance agreement for the overriding royalty interest. The claims appear to relate principally to farmout arrangements established in 2003 for two offshore properties, the Brazos Area Block A-7 and Brazos Area Block A-39. The relief sought by the plaintiff includes monetary and punitive damages and certain equitable relief, including an accounting of expenses, a setting aside of certain farmouts, and a temporary and permanent injunction. The Company believes the claims are without merit and intends to defend the lawsuit vigorously.

Argentine Environmental. The Company's subsidiary in Argentina is involved in various administrative proceedings with environmental authorities in the Neuquen Province relating to permits for and discharges from operations in that province. The Company's subsidiary is cooperating with the proceedings, although it from time to time challenges whether certain assessed fines are appropriate. The Company estimates that fines assessed in these proceedings will be immaterial, but in the aggregate could exceed \$100,000. The Company's subsidiary in Argentina has also been named in a suit against various oil companies operating in the Neuquen basin entitled *Asociación de Superficiarios de la Patagonia v. YPF S.A.*, *et. al.*, originally filed on August 21, 2003, in the Argentine National Supreme Court of Justice. The plaintiffs, a private group of landowners, have also named the national government and several provinces as third parties. The lawsuit alleges injury to the environment generally by the oil and gas industry without specifically alleging how any of the defendants caused this injury. The plaintiffs principally seek creation of an insured fund to remediate the environment. The Company's subsidiary intends to defend itself in the case. Although the suit is at an early procedural stage and appears to involve novel theories, the Company does not expect that any such additional 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.

Dorchester Refining Company Site. A subsidiary of the Company has been notified by a letter from the Texas Commission on Environmental Quality ("TCEQ") dated August 24, 2005 that the TCEQ considers the subsidiary to be a potentially responsible party with respect to the Dorchester Refining Company State Superfund Site located in Mount Pleasant, Texas. In connection with the acquisition of oil and gas assets in 1991, the Company acquired a group of companies, one of which was an entity that had owned a refinery located at the Mount Pleasant site from 1977 until 1984. According to the TCEQ, this refinery was responsible for releases of hazardous substances into the environment. Pursuant to applicable Texas law, the Company's subsidiary, which does not own any material assets or conduct any material operations, may be subject to strict, joint and several liability for the costs of conducting a study to evaluate potential remedial options and for the costs of performing any remediation ultimately required by the TCEQ. The Company does not know the nature and extent of the alleged contamination, the potential costs of remediation, or the portion, if any, of such costs that may be allocable to the Company's subsidiary; however, the Company has noted that there appear to be other operators or owners who may share responsibility for these costs and does not expect that any such additional 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.

Environmental Protection Agency Investigation. On November 4, 2005, the Company learned from the U.S. Environmental Protection Agency that the agency was conducting a criminal investigation into a 2003 spill that occurred at a Company-operated drilling rig located on an ice island offshore Kuparuk in Harrison Bay, Alaska. The investigation is being conducted in conjunction with the U.S. Attorney's Office for the District of Alaska. The spill was previously investigated by the Alaska Department of Environmental Conservation ("ADEC") and, following completion of a clean up, the ADEC issued a letter stating its determination that, at that time, the site did not pose a threat to human health, safety, or welfare or the environment. The Company is cooperating in the government's investigation.

Lease agreements. The Company leases offshore production facilities, drilling rigs, equipment and office facilities under noncancellable operating leases. Rental expenses associated with these operating leases for the years ended December 31, 2005, 2004 and 2003 were approximately \$64.5 million, \$51.8 million and \$15.5 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2005 are as follows (in thousands):

2006	\$57,931
2007	\$42,384
2008	\$28,302
2009	\$19,373
2010	\$10,173
Thereafter	\$ 5,642

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

Transportation agreements. Associated with the Evergreen merger, the Company assumed gas transportation commitments for specified volumes of gas per year through 2014. During 2005, the Company expanded these commitments to support production increases, primarily in the Raton gas field. The transportation commitments averaged approximately 147 million cubic feet ("MMcf") of gross gas sales volumes per day during 2005, including associated fuel commitments. These commitments will average approximately 196 MMcf of gross gas volumes per day during 2006, increase to approximately 200 MMcf of gross gas volumes per day during 2007, and decline thereafter to approximately 41 MMcf of gross gas volumes per day during 2014.

The Company's Canadian subsidiaries are parties to pipeline transportation service agreements, with aggregate remaining terms of approximately 10 years, whereby they have committed to transport specified volumes of gas each year principally from Canada to a point in Chicago, Illinois. Such gas volumes totaled approximately 78 MMcf of gas per day during 2005, 2004 and 2003, and are comprised of a significant portion of the Company's Canadian net gas 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 86 MMcf of gas per day during 2006 and decline to approximately 75 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 $4.1 million of gas marketing gains in other income during the year ended December 31, 2005 and $1.2 million and $.9 million, respectively, of gas marketing losses in other expense during the years ended December 31, 2004 and 2003.

Future minimum transportation fees under the Company's gas transportation commitments at December 31, 2005 are as follows (in thousands):

2006	$ 67,222
2007	$ 68,531
2008	$ 68,345
2009	$ 67,865
2010	$ 66,749
Thereafter	$234,986

NOTE J. Derivative Financial Instruments

Fair value hedges. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate swap contracts with the objective of reducing costs of capital. During the three-year period ending December 31, 2005, the Company entered into interest rate swap contracts to hedge a portion of the fair value of its senior notes. During the year ended December 31, 2004, the Company paid $9.4 million, net of $2.2 million of associated settlements receivable, to terminate fair value hedge interest rate swaps prior to their stated maturities. Associated therewith, the Company recognized $11.6 million of "Payments of other liabilities" in the accompanying Consolidated Statement of Cash Flows for the year ended December 31, 2004. During the year ended December 31, 2003, the Company terminated fair value hedge interest rate swap contracts for cash proceeds, including accrued interest, of $21.5 million. The proceeds attributable to the fair value of the remaining terms of the terminated contracts amounted to $18.3 million and are included in "Proceeds from disposition of assets" in the accompanying Consolidated Statements of Cash Flows during the year ended December 31, 2003. During the years ended December 31, 2004 and 2003, settlements of open fair value hedges reduced the Company's interest expense by $2.2 million and $3.2 million, respectively. As of December 31, 2005 and 2004, the Company was not a party to any open fair value hedges.

As of December 31, 2005, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included a $4.3 million reduction in the carrying value attributable to net deferred hedge losses on terminated fair value hedges that are being amortized as net increases to interest expense over the original terms of the terminated agreements. The amortization of net deferred hedge gains on terminated interest rate swaps reduced the Company's reported interest expense by $4.1 million, $19.2 million and $26.1 million during the years ended December 31, 2005, 2004 and 2003, respectively.

The following table sets forth, as of December 31, 2005, the scheduled amortization of net deferred hedge gains (losses) on terminated interest rate hedges (including terminated fair value and cash flow hedges) that will be recognized as increases in the case of losses, or decreases in the case of gains, to the Company's future interest expense:

	Year Ending December 31,					
	2006	2007	2008	2009	2010	Thereafter
	(In thousands)					
Net deferred hedge gains (losses)	$107	$(1,573)	$(554)	$(528)	$(578)	$(4,355)

Cash flow hedges. The Company utilizes commodity swap and collar contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. As of December 31, 2005, all of the Company's open commodity hedges are designated as hedges of Canadian and United States forecasted sales. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness and forward currency exchange agreements to reduce the effect of U.S. dollar to Canadian dollar exchange rate volatility.

Oil prices. All material physical sales contracts governing the Company's oil production have been tied directly or indirectly to the New York Mercantile Exchange ("NYMEX") prices. As of December 31, 2005, all of the Company's oil hedges were designated as hedges of United States forecasted sales. The following table sets forth the volumes hedged in barrels ("Bbl") underlying the Company's outstanding oil hedge contracts and the weighted average NYMEX prices per Bbl for those contracts as of December 31, 2005:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily oil production hedged(a):					
2006 — Swap Contracts					
Volume (Bbl)	10,000	10,000	10,000	10,000	10,000
Price per Bbl	$ 31.69	$ 31.69	$ 31.69	$ 31.69	$ 31.69
2006 — Collar Contracts					
Volume (Bbl)	8,500	9,000	9,500	9,500	9,129
Price per Bbl	$43.82-$73.43	$44.17-$74.63	$44.47-$75.70	$44.47-$75.70	$44.25-$74.92
2007 — Swap Contracts					
Volume (Bbl)	13,000	13,000	13,000	13,000	13,000
Price per Bbl	$ 30.89	$ 30.89	$ 30.89	$ 30.89	$ 30.89
2007 — Collar Contracts					
Volume (Bbl)	4,500	4,500	4,500	4,500	4,500
Price per Bbl	$50.00-$90.43	$50.00-$90.43	$50.00-$90.43	$50.00-$90.43	$50.00-$90.43
2008 — Swap Contracts					
Volume (Bbl)	17,000	17,000	17,000	17,000	17,000
Price per Bbl	$ 29.21	$ 29.21	$ 29.21	$ 29.21	$ 29.21

(a) Subsequent to December 31, 2005, the Company reduced its oil hedge positions by terminating the following oil swap and collar contracts which are included in the table above: (i) 2,000 Bbls per day of March through December 2006 swap contracts with a fixed price of $26.29 per Bbl; 1,000 Bbls per day of calendar 2007 swap contracts with a fixed price of $31.00 per Bbl; and 2,000 Bbls per day of calendar 2008 swap contracts with a fixed price of $30.00 per Bbl and (ii) 2,000 Bbls per day of March through December 2006 collar contracts having a floor price of $50.00 per Bbl and a ceiling price of $96.25 per Bbl and 2,500 Bbls per day of calendar 2007 collar contracts having a floor price of $50.00 and ceiling prices of $91.18 per Bbl.

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 from continuing operations, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of oil price hedges on oil revenue for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Average price reported per Bbl	$ 37.22	$31.60	$25.50
Average price realized per Bbl	$ 50.74	$37.49	$28.71
Reduction to oil revenue (in millions)(a)	$(217.5)	$ (97.0)	$ (38.9)

(a) Excludes hedge losses of $11.1 million, $10.2 million and $2.4 million attributable to discontinued operations for the years ended December 31, 2005, 2004 and 2003, respectively.

Natural gas liquids prices. During the years ended December 31, 2005, 2004 and 2003, the Company did not enter into any NGL hedge contracts. There were no outstanding NGL hedge contracts at December 31, 2005.

Gas prices. The Company employs a policy of hedging a portion of its gas production based on the index price upon which the gas is actually sold in order to mitigate the basis risk between NYMEX prices and actual index prices, or based on NYMEX prices if NYMEX prices are highly correlated with the index price. As of December 31, 2005, all of the Company's gas hedges were designated as hedges of United States and Canadian forecasted sales. The following table sets forth the volumes hedged in million British thermal units ("MMBtu") under outstanding gas hedge contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2005:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily gas production hedged(a):					
2006 — Swap Contracts					
Volume (MMBtu)	73,710	73,790	73,880	73,984	73,842
Index price per MMBtu	$ 4.30	$ 4.30	$ 4.31	$ 4.31	$ 4.30
2006 — Collar Contracts					
Volume (MMBtu)	200,000	175,000	175,000	185,000	183,685
Index price per MMBtu	$6.72-$13.17	$6.58-$13.90	$6.58-$13.90	$6.58-$14.11	$6.62-$13.76
2007 — Swap Contracts					
Volume (MMBtu)	29,071	29,146	29,231	29,329	29,195
Index price per MMBtu	$ 4.27	$ 4.28	$ 4.29	$ 4.29	$ 4.28
2007 — Collar Contracts					
Volume (MMBtu)	215,000	215,000	215,000	215,000	215,000
Index price per MMBtu	$6.57-$11.84	$6.57-$11.84	$6.57-$11.84	$6.57-$11.84	$6.57-$11.84
2008 — Swap Contracts					
Volume (MMBtu)	5,000	5,000	5,000	5,000	5,000
Index price per MMBtu	$ 5.38	$ 5.38	$ 5.38	$ 5.38	$ 5.38

(a) Subsequent to December 31, 2005, the Company reduced its gas hedge positions by terminating the following gas collar contracts which are included in the table above: (i) 65,000 MMBtu per day of April through December 2006 gas sales at a weighted average floor price per MMBtu of $6.74 and a weighted average ceiling price per MMBtu of $14.01.

The Company reports average gas prices per thousand cubic feet ("Mcf") including the effects of British thermal unit ("Btu") content, gas processing, shrinkage adjustments and the net effect of gas hedges. The following table sets forth the Company's gas prices from continuing operations, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of gas price hedges on gas revenue for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Average price reported per Mcf	$ 5.66	$ 4.30	$ 3.78
Average price realized per Mcf	$ 6.49	$ 4.78	$ 4.15
Reduction to gas revenue (in millions)(a)	$(202.9)	$(114.9)	$(71.8)

(a) Excludes hedge losses of $10.8 million and $4.3 million attributable to discontinued operations for the years ended December 31, 2004 and 2003, respectively.

Hedge ineffectiveness. During the years ended December 31, 2005, 2004 and 2003, the Company recognized ineffectiveness charges to other expense of $54.8 million, $4.3 million and $2.8 million, respectively, related to the ineffective portions of its cash flow hedging instruments. These charges include amounts related to (i) hedged volumes that exceeded revised forecasts of production volumes due to delays in the start up of production in certain fields and (ii) reduced correlations between the indexes of the financial hedge derivatives and the indexes of the hedged forecasted production for certain fields.

AOCI — Hedging. As of December 31, 2005 and 2004, AOCI — Hedging represented net deferred losses of $506.6 and $241.4 million, respectively. The AOCI — Hedging balance as of December 31, 2005 was comprised of $767.8 million of net deferred losses on the effective portions of open cash flow hedges, $30.0 million of net deferred losses on terminated cash flow hedges (including $3.2 million of net deferred losses on terminated cash flow interest rate hedges) and $291.2 million of associated net deferred tax benefits. The AOCI — Hedging balance as of December 31, 2004 was comprised of $363.1 million of net deferred losses on the effective portions of open cash flow hedges, $3.0 million of net deferred losses on terminated cash flow hedges (including $3.4 million of net deferred losses on terminated cash flow interest rate hedges) and $124.7 million of associated net deferred tax benefits. The increase in AOCI — Hedging during the year ended December 31, 2005 was primarily attributable to increases in future commodity prices relative to the commodity prices stipulated in the hedge contracts, partially offset by the reclassification of net deferred hedge losses to net income as derivatives matured by their terms. The net deferred losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The net deferred losses on terminated cash flow hedges are fixed.

During the year ending December 31, 2006, based on current estimates of future commodity prices, the Company expects to reclassify $308.3 million of net deferred losses associated with open commodity hedges and $6.2 million of net deferred losses on terminated commodity hedges from AOCI — Hedging to oil and gas revenues. The Company also expects to reclassify approximately $114.8 million of net deferred income tax benefits associated with commodity hedges during the year ending December 31, 2006 from AOCI — Hedging to income tax benefit.

The following table sets forth, as of December 31, 2005, the scheduled amortization of net deferred gains (losses) on terminated commodity hedges that will be recognized as decreases in the case of losses, and increases in the case of gains, to the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(In thousands)		
2006 net deferred hedge losses	$(5,098)	$(302)	$ (59)	$(727)	$ (6,186)
2007 net deferred hedge gains (losses)	$(3,764)	$ 148	$ 424	$(347)	(3,539)
2008 net deferred hedge losses	$(2,877)	$(372)	$(284)	$(839)	(4,372)
2009 net deferred hedge losses	$(2,330)	$(232)	$(230)	$(822)	(3,614)
2010 net deferred hedge losses	$ (667)	$(620)	$(578)	$(539)	(2,404)
2011 net deferred hedge losses	$ (873)	$(889)	$(903)	$(906)	(3,571)
2012 net deferred hedge losses	$ (810)	$(791)	$(784)	$(772)	(3,157)
					$(26,843)

Non-hedge derivatives. During January and April 2005, the Company entered into non-hedge interest rate swaps. The Company terminated the interest rate swaps during January and April 2005 for an aggregate net loss of $1.5 million, which amount is included in other expense in the Company's accompanying Consolidated Statement of Operations for 2005.

NOTE K. Major Customers and Derivative Counterparties

Sales to major customers. The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company records allowances for doubtful accounts based on the agings of accounts receivable and the general economic condition of its customers. 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.

There were not any customers who individually accounted for ten percent or more of the consolidated oil, NGL and gas revenues of the Company during the year ended December 31, 2005. The following customer individually accounted for ten percent or more of the consolidated oil, NGL and gas revenues of the Company, including the revenues from discontinued operations and the results of commodity hedges, during the years ended December 31, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
Williams Power Company, Inc.	9%	14%	16%

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, 2005 and 2004, the Company had $7.3 million of derivative assets for which Enron North America Corp was the Company's counterparty. Associated therewith, the Company had a $6.4 million allowance for doubtful accounts as of December 31, 2005 and 2004. In January 2006, the Company sold the Enron receivables for $3.0 million and will recognize a gain of $2.1 million in 2006.

NOTE L. Asset Retirement Obligations

As referred to in Note B, the Company adopted the provisions of SFAS 143 on January 1, 2003. The Company's asset retirement obligations primarily relate to the future plugging and abandonment of proved properties and related facilities. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes the Company's asset retirement obligation transactions recorded in accordance with the provisions of SFAS 143 during the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Beginning asset retirement obligations	$120,879	$105,036	$ 34,692
Cumulative effect adjustment	—	—	23,393
New wells placed on production and changes in estimates(a)	57,575	4,591	46,664
Liabilities assumed in acquisitions	3,013	10,488	1,791
Disposition of wells	(23,101)	—	—
Liabilities settled	(9,508)	(8,562)	(8,069)
Accretion of discount	7,876	8,210	5,040
Currency translation	301	1,116	1,525
Ending asset retirement obligations	$157,035	$120,879	$105,036

(a) Includes, for the year ended December 31, 2005, a $39.8 million increase in the abandonment estimate of the East Cameron facilities that were destroyed by Hurricane Rita, which is reflected in exploration and abandonments expense in the Consolidated Statements of Operations.

The Company records the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities and minority interests, respectively, in the accompanying Consolidated Balance Sheets.

NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Business interruption insurance claim (see Note U)	$73,637	$ 7,563	$ —
Excise tax income	5,577	3,609	2,369
Minority interest in subsidiary's net loss	5,206	—	—
Canadian alliance marketing gain (see Note I)	4,127	—	—
Interest income	2,247	328	981
Sales and other tax refunds	1,792	—	—
Credit card rebate	835	—	—
Seismic data sales	723	172	424
Deferred compensation plan income	500	202	140
Foreign currency remeasurement and exchange gains(a)	392	304	657
Gain on early extinguishment of debt (see Note F)	—	95	—
Postretirement obligation revaluations (see Note H)	—	32	4,410
Other income	2,014	1,769	3,311
Total interest and other income	$97,050	$14,074	$12,292

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

NOTE N. Asset Divestitures

During the years ended December 31, 2005, 2004 and 2003, the Company completed asset divestitures for net proceeds of $1.2 billion, $1.7 million and $35.7 million, respectively. Associated therewith, the Company recorded gains on disposition of assets in continuing operations of $60.5 million, $39,000 and $1.3 million during the years ended December 31, 2005, 2004 and 2003, respectively, and gains of $166.1 million in discontinued operations in 2005. The following represent the significant divestitures:

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

Canadian and Gulf of Mexico Shelf divestitures. During 2005, the Company sold its interests in (a) the Martin Creek, Conroy Black and Lookout Butte areas in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million and (b) certain assets on the Gulf of Mexico shelf for net proceeds of $59.1 million, resulting in a gain of $27.7 million. Pursuant to SFAS 144, the gain and the results of operations from these assets have been reclassified to discontinued operations. See Note V for additional information.

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

Gabon divestiture. In October 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owns the interest in the Olowi block for $47.9 million of net proceeds. A gain was recognized during the fourth quarter of 2005 of $47.5 million with no associated income tax effect either in Gabon or the United States. In addition, Pioneer retains the potential, under certain circumstances, to receive additional payments for production from deeper reservoirs discovered on the block.

Hedge derivative divestitures. During the year ended December 31, 2003, the Company terminated, prior to their scheduled maturity, hedge derivatives for cash sales proceeds of $18.3 million. Net gains from these divestitures were deferred and are 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 and losses on terminated hedge derivatives.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Derivative ineffectiveness and mark-to-market provisions (see Note J)	$ 56,318	$ 4,341	$ 2,831
Loss on early extinguishment of debt (see Note F)	26,464	—	1,457
Contingency accrual adjustments (see Note I)	11,767	13,552	1,776
Foreign currency remeasurement and exchange losses(a)	3,978	2,949	2,672
Noncompete agreement amortization	3,914	798	—
Minority interest in subsidiaries' net income	3,482	896	—
Postretirement obligation revaluation	3,211	—	—
Argentine personal asset tax	1,251	1,094	1,996
Bad debt expense	452	3,674	354
Debt exchange offer costs (see Note F)	11	2,248	—
Canadian alliance marketing losses (see Note I)	—	1,218	922
Other charges	1,964	2,917	9,312
Total other expense	$112,812	$33,687	$21,320

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

NOTE P. Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"). The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state, local and foreign taxing authorities. Current and estimated tax payments of $44.7 million, $17.1 million and $5.3 million were made during the years ended December 31, 2005, 2004 and 2003, respectively.

SFAS 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the United States, state, local and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2005 and 2004, the Company's valuation allowances related to foreign and domestic tax jurisdictions were $95.8 million and $108.2 million, respectively.

In October 2004, the American Jobs Creation Act (the "AJCA") was signed into law. The AJCA includes a deduction of 85 percent of qualified foreign earnings that are repatriated, as defined in the AJCA. During 2005, the Company determined that it was advantageous to apply the provisions of the AJCA to qualified foreign earnings that could be repatriated. The Company formalized repatriation plans in 2005 and repatriated $322.5 million from Canada, South Africa and Tunisia. Based on the current understanding of the provisions of the AJCA, the Company estimates that approximately $170.7 million of the repatriated funds qualify for the dividend exclusion. The Company is obligated by the provisions of the AJCA to invest the qualifying dividends in the United States within a reasonable period of time. The cash tax liability associated with the qualifying dividends is approximately $9.3 million for 2005. During the year ended December 31, 2005, the Company recognized income tax expense of $6.8 million related to continuing operations and $19.6 million related to discontinued operations associated with the repatriations.

The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Income from continuing operations before cumulative effect of change in accounting principle	$ 291,728	$164,164	$ (67,368)
Income from discontinued operations	73,117	2,195	2,965
Cumulative effect of change in accounting principle	—	—	1,312
Changes in goodwill — tax benefits related to stock based compensation	(7,255)	(8,955)	—
Changes in stockholders' equity:			
Net deferred hedge losses	(166,572)	(73,340)	(51,064)
Tax benefits related to stock-based compensation	(18,752)	(6,612)	(14,666)
Translation adjustment	3,685	(314)	(324)
	$ 175,951	$ 77,138	$(129,145)

The Company's income tax provision (benefit) attributable to income from continuing operations before cumulative effect of change in accounting principle consisted of the following for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Current:			
U.S. federal	$ 13,104	$ 2,500	$ 100
U.S. state and local	(254)	602	—
Foreign	42,292	22,185	11,085
	55,142	25,287	11,185
Deferred:			
U.S. federal	214,617	136,618	(71,863)
U.S. state and local	8,336	5,003	(7,413)
Foreign	13,633	(2,744)	723
	236,586	138,877	(78,553)
	$291,728	$164,164	$(67,368)

Income from continuing operations before income taxes and cumulative effect of change in accounting principle consists of the following for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
U.S. federal	$547,547	$471,181	$327,039
Foreign	167,912	(8,088)	(16,610)
	$715,459	$463,093	$310,429

Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income from continuing operations before cumulative effect of change in accounting principle are as follows for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
	(In percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
State income taxes (net of federal benefit)	1.3	1.4	0.4
U.S. valuation allowance changes	0.1	—	(63.7)
Foreign valuation allowances(a)	1.6	5.3	14.0
Rate differential on foreign operations	0.1	4.5	(1.0)
Argentine inflation adjustment(a)	(1.5)	(2.1)	(13.2)
Gabon investment deduction	3.6	(5.6)	—
Gabon tax free book gain	(2.3)	—	—
Repatriation of foreign earnings	0.9	—	—
Other	2.0	(3.1)	6.8
Consolidated effective tax rate	40.8	35.4	(21.7)

(a) The Company has applied an inflation adjustment to its Argentine income tax returns since 2002 based on developing case law. The Company believes that it is more likely than not that the adjustment will be denied by the Argentine taxing authorities and has provided a $58.9 million valuation allowance against this tax benefit in its overall foreign valuation allowances as of December 31, 2005.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows as of December 31, 2005 and 2004:

	December 31, 2005	December 31, 2004
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 191,314	$ 303,002
Alternative minimum tax credit carryforwards	10,725	4,144
Net deferred hedge losses	291,216	124,689
Asset retirement obligations	54,338	41,874
Other	95,073	110,677
Total deferred tax assets	642,666	584,386
Valuation allowances	(95,750)	(108,214)
Net deferred tax assets	546,916	476,172
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	1,053,989	898,753
Other	101,378	71,685
Total deferred tax liabilities	1,155,367	970,438
Net deferred tax liability	$ (608,451)	$(494,266)

At December 31, 2005, the Company had NOLs for United States, South Africa and other African countries for income tax purposes as set forth below, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, the Company has alternative minimum tax NOLs ("AMT NOLs") in the United States which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

Expiration Date	U.S. NOL	U.S. AMT NOL	South Africa NOL	Other African NOLs(a)
	(In thousands)			
2018	$100,460	$ 52,906	$ —	$ —
2019	156,737	155,353	—	—
2020	20,861	19,746	—	—
2021	46,746	43,628	—	—
2022	41,780	39,950	—	—
2023	81,040	81,259	—	—
Indefinite	—	—	20,867	63,115
	$447,624	$392,842	$20,867	$63,115

(a) The Company believes that it is more likely than not that these other African NOLs will not offset future taxable income and has provided a valuation allowance against these deferred tax assets.

The Company believes $100 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 million. During the years ended

December 31, 2005, 2004 and 2003, the Company utilized $354.9 million, $151.1 million and $16.3 million of NOLs, respectively.

NOTE Q. Income Per Share From Continuing Operations Before Cumulative Effect of Change in Accounting Principle

Basic income per share from continuing operations before cumulative effect of change in accounting principle is computed by dividing income from continuing operations before cumulative effect of change in accounting principle by the weighted average number of common shares outstanding for the period. The computation of diluted income per share from continuing operations before cumulative effect of change in accounting principle reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income from continuing operations before cumulative effect of change in accounting principle 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 income from continuing operations before cumulative effect of change in accounting principle to diluted income from continuing operations before cumulative effect of change in accounting principle for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Basic income from continuing operations before cumulative effect of change in accounting principle	$423,731	$298,929	$377,797
Interest expense on convertible notes, net of tax	3,207	802	—
Diluted income from continuing operations before cumulative effect of change in accounting principle	$426,938	$299,731	$377,797

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Weighted average common shares outstanding(a):			
Basic	137,110	125,156	117,185
Dilutive common stock options(b)	1,136	1,218	1,112
Restricted stock awards	844	529	216
Convertible notes dilution(c)	2,327	585	—
Diluted	141,417	127,488	118,513

(a) During August 2005, the Board approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock, $640.7 million of which was completed in 2005 and $350 million is subject to the successful completion of the planned deepwater Gulf of Mexico and Argentine divestments.

(b) Common stock options to purchase 30,712 shares and 976,506 shares of common stock were outstanding but not included in the computations of diluted income per share from continuing operations before cumulative effect of change in accounting principle for 2004 and 2003, 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.

(c) Associated with the Evergreen merger, the Company assumed convertible notes eligible for 2.3 million shares of the Company's common stock upon conversion.

NOTE R. Geographic Operating Segment Information

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

During 2005, the Company sold certain Canadian and United States oil and gas properties having carrying values of $58.9 million and $31.4 million, respectively, on their dates of sale. The results of operations of those properties have been reclassified as discontinued operations in accordance with SFAS 144 and are excluded from the geographic operating segment information provided below. See Note V for information regarding the Company's discontinued operations.

The following tables provide the Company's geographic operating segment data required by SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information", as well as results of operations of oil and gas producing activities required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities" as of and for the years ended December 31, 2005, 2004 and 2003. Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters" table column includes income and expenses that are not routinely included in the earnings measures internally reported to management on a geographic operating segment basis.

	United States	Argentina	Canada	Africa and Other	Headquarters	Consolidated Total
				(In thousands)		
Year Ended December 31, 2005:						
Revenues and other income:						
Oil and gas	$1,734,412	$172,187	$114,357	$194,721	$ —	$2,215,677
Interest and other	—	—	—	—	97,050	97,050
Gain (loss) on disposition of assets, net	12,114	—	(221)	47,352	1,251	60,496
	1,746,526	172,187	114,136	242,073	98,301	2,373,223
Costs and expenses:						
Oil and gas production	341,422	38,756	36,725	32,417	—	449,320
Depletion, depreciation and amortization	401,320	84,618	31,469	29,252	21,359	568,018
Impairment of oil and gas properties	—	—	—	644	—	644
Exploration and abandonments	176,027	24,527	9,545	56,652	—	266,751
General and administrative	—	—	—	—	124,556	124,556
Accretion of discount on asset retirement obligations	—	—	—	—	7,876	7,876
Interest	—	—	—	—	127,787	127,787
Other	—	—	—	—	112,812	112,812
	918,769	147,901	77,739	118,965	394,390	1,657,764
Income (loss) from continuing operations before income taxes	827,757	24,286	36,397	123,108	(296,089)	715,459
Income tax benefit (provision)	(302,131)	(8,500)	(13,285)	(75,190)	107,378	(291,728)
Income (loss) from continuing operations	$ 525,626	$ 15,786	$ 23,112	$ 47,918	$(188,711)	$ 423,731
Costs incurred for oil and gas assets	$ 903,390	$129,640	$131,237	$115,269	$ —	$1,279,536
Segment assets (as of December 31, 2005)	$5,899,637	$735,191	$363,773	$170,484	$ 160,149	$7,329,234

	United States	Argentina	Canada	Africa and Other	Headquarters	Consolidated Total
			(In thousands)			
Year Ended December 31, 2004:						
Revenues and other income:						
Oil and gas	$1,419,938	$134,065	$ 50,447	$162,921	$ —	$1,767,371
Interest and other	—	—	—	—	14,074	14,074
Gain (loss) on disposition of assets, net	51	—	(252)	—	240	39
	1,419,989	134,065	50,195	162,921	14,314	1,781,484
Costs and expenses:						
Oil and gas production	232,613	33,174	18,810	31,510	—	316,107
Depletion, depreciation and amortization	411,325	61,773	22,551	47,835	12,780	556,264
Impairment of oil and gas properties	—	—	—	39,684	—	39,684
Exploration and abandonments	98,984	23,406	19,061	39,299	—	180,750
General and administrative	—	—	—	—	80,302	80,302
Accretion of discount on asset retirement obligations	—	—	—	—	8,210	8,210
Interest	—	—	—	—	103,387	103,387
Other	—	—	—	—	33,687	33,687
	742,922	118,353	60,422	158,328	238,366	1,318,391
Income (loss) from continuing operations before income taxes	677,067	15,712	(10,227)	4,593	(224,052)	463,093
Income tax benefit (provision)	(247,129)	(5,499)	3,861	1,413	83,190	(164,164)
Income (loss) from continuing operations	$ 429,938	$ 10,213	$ (6,366)	$ 6,006	$(140,862)	$ 298,929
Costs incurred for oil and gas assets	$2,876,185	$102,452	$120,626	$ 74,906	$ —	$3,174,169
Segment assets (as of December 31, 2004)	$5,460,708	$708,391	$316,124	$123,073	$ 125,191	$6,733,487

	United States	Argentina	Canada	Africa and Other	Headquarters	Consolidated Total
				(In thousands)		
Year Ended December 31, 2003:						
Revenues and other income:						
Oil and gas	$1,025,951	$111,315	$ 50,012	$ 21,343	$ —	$1,208,621
Interest and other	—	—	—	—	12,292	12,292
Gain (loss) on disposition of assets, net	1,458	—	1	—	(203)	1,256
	1,027,409	111,315	50,013	21,343	12,089	1,222,169
Costs and expenses:						
Oil and gas production	182,476	26,110	16,710	2,887	—	228,183
Depletion, depreciation and amortization	289,724	46,518	20,727	7,729	9,597	374,295
Exploration and abandonments	72,739	18,076	16,116	24,261	—	131,192
General and administrative	—	—	—	—	60,322	60,322
Accretion of discount on asset retirement obligations	—	—	—	—	5,040	5,040
Interest	—	—	—	—	91,388	91,388
Other	—	—	—	—	21,320	21,320
	544,939	90,704	53,553	34,877	187,667	911,740
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	482,470	20,611	(3,540)	(13,534)	(175,578)	310,429
Income tax benefit (provision)	(176,102)	(7,214)	1,363	4,738	244,583	67,368
Income (loss) from continuing operations before cumulative effect of change in accounting principle	$ 306,368	$ 13,397	$ (2,177)	$ (8,796)	$ 69,005	$ 377,797
Costs incurred for oil and gas assets	$ 602,167	$ 51,671	$ 54,800	$ 62,817	$ —	$ 771,455
Segment assets (as of December 31, 2003)	$2,645,153	$675,425	$224,921	$159,747	$ 246,326	$3,951,572

NOTE S. Impairment of Oil and Gas Properties

During October 2004, the Company concluded that a material charge for impairment was required under SFAS 144 for its Gabonese Olowi field as development of the discovery was canceled. Due to significant increases in projected field development costs, primarily due to increases in steel costs, the project did not offer competitive returns. The Olowi field was the Company's only Gabonese investment. During 2005 and 2004, the Company recorded an associated impairment charge to eliminate the carrying value of the Company's Gabonese Olowi field of $644,000 and $39.7 million, respectively.

NOTE T. Volumetric Production Payments

During January 2005, the Company sold two percent of its total proved reserves, or 20.5 million Bbls oil equivalent ("MMBOE") of proved reserves, by means of two VPPs for net proceeds of $592.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to reduce outstanding indebtedness. The first January VPP sold 58 billion cubic feet ("Bcf") of gas volumes over an expected five-year term that began in February 2005 for $275.2 million. The second January VPP sold 10.8 million Bbls ("MMBbls") of oil volumes over an expected seven-year term that began in January 2006 for $317.1 million.

During April 2005, the Company sold less than one percent of its total proved reserves, or 7.3 MMBOE of proved reserves, by means of a VPP for net proceeds of $300.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPP were initially used to reduce outstanding indebtedness. The April VPP sold 6.0 Bcf of gas volumes over an expected 32-month term that began in May 2005 and 6.2 MMBbls of oil volumes over an expected five-year term that began in January 2006.

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

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

The following table represents the breakdown of the components of the Company's VPPs:

	January VPPs		April VPP		
	Hugoton Field (Gas)	Spraberry Field (Oil)	Spraberry Field (Gas)	Spraberry Field (Oil)	Total
			(In thousands)		
VPP proceeds, net of transaction costs	$275,161	$317,120	$37,601	$262,712	$892,594
Fair value of derivatives conveyed(a)	12,860	36,759	(526)	(11,076)	38,017
Deferred revenue	288,021	353,879	37,075	251,636	930,611
Less 2005 amortization	(65,801)	—	(9,972)	—	(75,773)
Deferred revenue at December 31, 2005	$222,220	$353,879	$27,103	$251,636	$854,838

(a) Represents the fair value of the derivative obligations conveyed as part of the VPP transactions. The fair value was deferred in AOCI — Hedging until the delivery of the VPP volumes occurs at which time the fair value of the derivative obligations attributable to the delivered volumes is being recognized as increases or decreases to oil and gas revenues. See Note J for additional discussion regarding the Company's hedge positions.

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

2006	$190,327
2007	181,232
2008	158,138
2009	147,906
2010	90,215
2011	44,951
2012	42,069
	$854,838

NOTE U. Insurance Claims

Hurricane Ivan. During September 2004, the Company sustained damages as a result of Hurricane Ivan at its Devils Tower and Canyon Express platform facilities in the deepwater Gulf of Mexico. The damages delayed scheduled well completions and interrupted production during the second half of 2004 and during the first half of 2005. The Company maintains business interruption insurance coverage for such circumstances. During 2004 and 2005, the Company filed claims with its insurance providers for its estimated losses associated with Hurricane Ivan.

Based on a settlement agreement between the Company and the insurance providers, the Company's recoverable business interruption loss related to Hurricane Ivan is $67.0 million. The Company recorded $7.6 million and $59.4 million of the claims in the fourth quarter of 2004 and in the first half of 2005, respectively, in interest and other income in the Company's Consolidated Statements of Operations.

Fain Plant. During May 2005, the Company sustained damages as a result of a fire at its Fain gas plant in the West Panhandle field. The damages interrupted production from mid-May through mid-July of 2005. The Company maintains business interruption and physical damage insurance coverage for such circumstances and has filed claims with its insurance providers. The Company estimates its aggregate Fain plant business interruption claims to be approximately $19 million to $20 million, of which $14.2 million is undisputed by the insurance provider. The Company is working to resolve the disputed amounts with the insurance provider. The Company recorded $14.2 million of the claims in interest and other income in the Company's Consolidated Statements of Operations for the year ended December 31, 2005.

Hurricanes Katrina and Rita. During August and September 2005, the Company sustained damages as a result of Hurricanes Katrina and Rita at various facilities in the Gulf of Mexico. Other than the East Cameron facility discussed further below, the Company believes the damages to the facilities are covered by physical damage insurance. The Company also maintains business interruption insurance related to specifically designated assets in the event there are extended periods of revenue interruption.

The Company filed a business interruption claim with its insurance provider related to its Devils Tower field resulting from its inability to sell production as a result of damages to third party facilities. The Company's business interruption claim is expected to cover losses of revenues from mid-October 2005 (end of 45-day deductible waiting period) until such point as the third party facilities could take the full production from the Devils Tower field, which the Company determined to have occurred in early December 2005. At December 31, 2005, the Company estimates that its business interruption recovery on Devils Tower to be $20 million to $24 million. The Company has not recorded any estimated recoveries due to certain pending issues which the Company expects to have resolved in the near future.

As a result of Hurricane Rita, the Company's East Cameron facility was destroyed and the Company currently does not plan to rebuild the facility based on the current economics of the field. The Company is in the process of evaluating the magnitude of the loss. Currently, the Company estimates that it will incur a minimum of $44 million to reclaim and completely abandon the East Cameron facility; thus, the Company recorded an additional abandonment obligation of approximately $39.8 million in 2005 which is included in exploration and abandonments in the Consolidated Statements of Operations for the year ended December 31, 2005.

The Company filed a claim with its insurance provider regarding the loss at East Cameron. Under the Company's insurance policy, the East Cameron facility has the following coverages: (a) $14 million of scheduled property value for the platform, (b) $4 million of scheduled business interruption insurance after a deductible waiting period, (c) greater of (1) 25 percent of the scheduled property value of the platform or (2) $5 million for debris removal coverage, in total, for all assets per occurrence and (d) $100 million of "make well safe" coverage, in total, for all assets per occurrence.

In December 2005, the Company received the scheduled value for the East Cameron assets and recognized a gain of $9.7 million, which is included in gain on disposition of assets, net in the Consolidated Statements of Operations. The Company has not recorded any estimated business interruption recoveries due to certain pending issues which the Company expects to have resolved in the near future. The Company believes that its debris removal and make well safe coverages, in combination, will substantially cover the losses to be incurred with the abandonment of the East Cameron facility. The Company has not recorded any estimated recoveries related to insurance due to the early nature of the claim and the need to better quantify the claim.

NOTE V. Discontinued Operations

During May 2005, the Company sold its interests in the Martin Creek, Conroy Black and Lookout Butte assets in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million and, during August 2005, sold certain assets on the Gulf of Mexico shelf for net proceeds of $59.1 million, resulting in a gain of $27.7 million. Pursuant to SFAS 144, the gains and the results of operations from these assets have been reclassified to discontinued operations. The following table represents the components of the Company's discontinued operations for the years ended December 31, 2005, 2004 and 2003:

	Year ended December 31,		
	2005	2004	2003
		(In thousands)	
Revenues and other income:			
Oil and gas	$ 43,909	$65,292	$65,250
Gain on disposition of assets(a)	166,088	—	—
	209,997	65,292	65,250
Costs and expenses:			
Oil and gas production	14,426	29,397	26,567
Depletion, depreciation and amortization(a)	11,210	18,610	16,545
Exploration and abandonments(a)	240	939	1,568
General and administrative	167	226	223
	26,043	49,172	44,903
Income from discontinued operations before income taxes	183,954	16,120	20,347
Income tax provision:			
Current	(2,541)	—	—
Deferred(a)	(70,576)	(2,195)	(2,965)
Income from discontinued operations	$110,837	$13,925	$17,382

(a) Represents the noncash components of discontinued operations included in the Company's Consolidated Statements of Cash Flows excluding approximately $36,000, $157,000 and $107,000 of cash payments for delay rentals included in exploration and abandonments for the years ended December 31, 2005, 2004 and 2003, respectively.

NOTE W. Subsequent Events

In January 2006, the Company entered into agreements to sell all of its interests in its oil and gas assets in Argentina for proceeds of approximately $675 million, subject to normal closing adjustments and the retention, subject to limitation, of certain obligations. The sale is expected to close during the latter part of the first quarter or in early April 2006. The Company expects that upon closing of the sale, the results of operations from these assets will be reflected as discontinued operations in its future financial statements.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2005, 2004 and 2003

Capitalized Costs

	December 31, 2005	December 31, 2004
	(In thousands)	
Oil and gas properties:		
Proved	$ 8,499,253	$ 7,663,446
Unproved	313,881	461,170
Capitalized costs for oil and gas properties	8,813,134	8,124,616
Less accumulated depletion, depreciation and amortization	(2,577,946)	(2,243,549)
Net capitalized costs for oil and gas properties	$ 6,235,188	$ 5,881,067

Costs Incurred for Oil and Gas Producing Activities

	Property Acquisition Costs					
	Proved	Unproved	Exploration Costs	Development Costs	Asset Retirement Obligations (a)	Total Costs Incurred
			(In thousands)			
Year Ended December 31, 2005:						
United States	$ 167,814	$ 60,561	$217,723	$448,383	$ 8,909	$ 903,390
Argentina	—	512	36,878	85,786	6,464	129,640
Canada	2,593	7,344	43,437	77,962	(99)	131,237
Africa and other	—	30,923	63,605	16,777	3,964	115,269
Total	$ 170,407	$ 99,340	$361,643	$628,908	$19,238	$1,279,536
Year Ended December 31, 2004:						
United States	$2,213,879	$301,856	$127,338	$229,636	$ 3,476	$2,876,185
Argentina	—	—	49,745	49,937	2,770	102,452
Canada	46,988	20,921	33,406	13,036	6,275	120,626
Africa and other	—	18,238	32,932	21,178	2,558	74,906
Total	$2,260,867	$341,015	$243,421	$313,787	$15,079	$3,174,169
Year Ended December 31, 2003:						
United States	$ 130,876	$ 12,264	$191,809	$228,064	$39,154	$ 602,167
Argentina	97	1,787	24,893	25,361	(467)	51,671
Canada	63	5,028	24,899	23,040	1,770	54,800
Africa and other	—	910	33,212	20,697	7,998	62,817
Total	$ 131,036	$ 19,989	$274,813	$297,162	$48,455	$ 771,455

(a) The Company adopted SFAS 143 on January 1, 2003. See Notes B and L for additional information regarding the Company's asset retirement obligations.

Results of Operations

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

Reserve Quantity Information

The estimates of the Company's proved oil and gas reserves as of December 31, 2005, 2004 and 2003, which are located in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The Company reports all reserves held under production sharing arrangements and concessions utilizing the "economic interest" method, which excludes the host country's share of proved reserves. Estimated quantities for production sharing arrangements reported under the "economic interest" method are subject to fluctuations in the prices of oil and gas and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. The reserve estimates as of December 31, 2005, 2004 and 2003 utilized respective oil prices of $59.62, $41.96 and $31.10 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $36.34, $29.12 and $20.26 per Bbl, and respective gas prices of $6.36, $4.76 and $4.23 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.

Proved reserves at December 31, 2005 include 9.2 MMBOE related to the ten-year extension periods contained in the Company's Argentine concession agreements. Upon approval by the government, the extension periods begin in 2016 and 2017 depending on the effective date that each concession agreement was granted. The Company believes, based on historical precedent, that such extensions will be obtained as a matter of course. The Argentine proved reserves also assume that the oil export tax expires as prescribed by law in February 2007 and that Argentine oil prices have parity with worldwide oil prices.

The following table provides a rollforward of total proved reserves by geographic area and in total for the years ended December 31, 2005, 2004 and 2003, as well as proved developed reserves by geographic area and in total as of the beginning and end of each respective year. Oil and NGL volumes are expressed in thousands of Bbls ("MBbls"), gas volumes are expressed in MMcf and total volumes are expressed in thousands of Bbls oil equivalent ("MBOE").

UNAUDITED SUPPLEMENTARY INFORMATION — (Continued)
Years Ended December 31, 2005, 2004 and 2003

	Year Ended December 31,								
	2005			2004			2003		
	Oil & NGLs (MBbls)	Gas(a) (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas(a) (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas(a) (MMcf)	MBOE
Total Proved Reserves:									
UNITED STATES									
Balance, January 1	363,257	3,000,335	863,313	362,751	1,553,976	621,747	337,631	1,483,971	584,960
Revisions of previous estimates	(5,471)	(141,473)	(29,049)	4,671	25,764	8,965	36,823	94,759	52,616
Purchases of minerals-in-place	65,800	83,179	79,663	11,803	1,571,053	273,646	4,422	57,124	13,942
New discoveries and extensions	225	103,616	17,494	1,017	56,690	10,465	250	80,769	13,712
Production	(16,311)	(197,391)	(49,210)	(16,974)	(200,598)	(50,407)	(16,375)	(162,647)	(43,483)
Sales of minerals-in-place	(21,729)	(97,410)	(37,964)	(11)	(6,550)	(1,103)	—	—	—
Balance, December 31	385,771	2,750,856	844,247	363,257	3,000,335	863,313	362,751	1,553,976	621,747
ARGENTINA									
Balance, January 1	33,168	560,374	126,564	33,469	549,856	125,112	31,532	532,081	120,211
Revisions of previous estimates	2,060	(137,640)	(20,881)	(3,040)	(61,483)	(13,287)	2,027	44,064	9,372
New discoveries and extensions	2,334	31,606	7,602	6,428	116,526	25,849	3,562	8,068	4,907
Production	(3,538)	(50,017)	(11,874)	(3,689)	(44,525)	(11,110)	(3,652)	(34,357)	(9,378)
Balance, December 31	34,024	404,323	101,411	33,168	560,374	126,564	33,469	549,856	125,112
CANADA									
Balance, January 1	4,095	119,869	24,073	2,407	93,829	18,045	2,361	119,328	22,249
Revisions of previous estimates	434	15,887	3,082	710	8,580	2,140	344	(14,920)	(2,143)
Purchases of minerals-in-place	—	292	49	823	22,127	4,511	—	—	—
New discoveries and extensions	652	55,130	9,840	541	10,656	2,317	73	4,630	845
Production	(311)	(15,665)	(2,922)	(386)88	(15,323)	(2,940)	(371)	(15,209)	(2,906)
Sales of minerals-in-place	(2,447)	(44,999)	(9,947)	—	—	—	—	—	—
Balance, December 31	2,423	130,514	24,175	4,095	119,869	24,073	2,407	93,829	18,045
AFRICA									
Balance, January 1	8,271	—	8,271	24,154	—	24,154	9,320	—	9,320
Revisions of previous estimates	184	—	184	(12,111)	—	(12,111)	(1,817)	—	(1,817)
New discoveries and extensions	2,043	60,395	12,109	502	—	502	17,374	—	17,374
Production	(3,674)	—	(3,674)	(4,274)	—	(4,274)	(723)	—	(723)
Balance, December 31	6,824	60,395	16,890	8,271	—	8,271	24,154	—	24,154
TOTAL									
Balance, January 1	408,791	3,680,578	1,022,221	422,781	2,197,661	789,058	380,844	2,135,380	736,740
Revisions of previous estimates	(2,793)	(263,226)	(46,664)	(9,770)	(27,139)	(14,293)	37,377	123,903	58,028
Purchases of minerals-in-place	65,800	83,471	79,712	12,626	1,593,180	278,157	4,422	57,124	13,942
New discoveries and extensions	5,254	250,747	47,045	8,488	183,872	39,133	21,259	93,467	36,838
Production	(23,834)	(263,073)	(67,680)	(25,323)	(260,446)	(68,731)	(21,121)	(212,213)	(56,490)
Sales of minerals-in-place	(24,176)	(142,409)	(47,911)	(11)	(6,550)	(1,103)	—	—	—
Balance, December 31	429,042	3,346,088	986,723	408,791	3,680,578	1,022,221	422,781	2,197,661	789,058

(a) The proved gas reserves as of December 31, 2005, 2004 and 2003 include 306,303 MMcf, 271,667 MMcf and 82,729 MMcf, respectively, of gas that will be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point. The above production amounts for 2005, 2004 and 2003 include approximately 14,452 MMcf, 9,605 MMcf and 8,221 MMcf of field fuel, respectively.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION — (Continued)
Years Ended December 31, 2005, 2004 and 2003

	Year Ended December 31,								
	2005			2004			2003		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE
Proved Developed Reserves:									
United States	223,749	2,045,275	564,628	209,349	1,202,264	409,727	209,948	1,067,701	387,899
Argentina	20,565	320,616	74,001	21,149	352,660	79,926	22,180	402,640	89,287
Canada	3,849	107,547	21,773	2,312	86,500	16,728	2,042	90,003	17,042
Africa	8,271	—	8,271	6,817	—	6,817	—	—	—
Balance, January 1	256,434	2,473,438	668,673	239,627	1,641,424	513,198	234,170	1,560,344	494,228
United States	210,680	1,875,866	523,324	223,749	2,045,275	564,628	209,349	1,202,264	409,727
Argentina	20,844	282,815	67,980	20,565	320,616	74,001	21,149	352,660	79,926
Canada	2,202	99,025	18,706	3,849	107,547	21,773	2,312	86,500	16,728
Africa	5,477	—	5,477	8,271	—	8,271	6,817	—	6,817
Balance, December 31	239,203	2,257,706	615,487	256,434	2,473,438	668,673	239,627	1,641,424	513,198

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 ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2005 commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge contracts, less associated estimated income taxes and discounted at ten percent, was a liability of approximately $436 million at December 31, 2005.

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.

UNAUDITED SUPPLEMENTARY INFORMATION — (Continued)
Years Ended December 31, 2005, 2004 and 2003

The following tables provide the standardized measure of discounted future cash flows by geographic area and in total for the years ended December 31, 2005, 2004 and 2003, as well as a roll forward in total for each respective year:

	December 31, 2005	2004	2003
		(In thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 37,171,750	$28,373,520	$17,760,911
Future production costs	(10,911,204)	(8,232,530)	(5,440,383)
Future development costs	(2,757,072)	(1,829,937)	(1,188,394)
Future income tax expense	(7,552,644)	(5,612,935)	(3,057,968)
	15,950,830	12,698,118	8,074,166
10% annual discount factor	(9,872,066)	(7,116,815)	(4,276,678)
Standardized measure of discounted future cash flows	$ 6,078,764	$ 5,581,303	$ 3,797,488
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 2,256,468	$ 1,747,737	$ 1,257,068
Future production costs	(366,362)	(289,742)	(233,399)
Future development costs	(353,182)	(234,309)	(136,663)
Future income tax expense	(282,661)	(221,733)	(161,683)
	1,254,263	1,001,953	725,323
10% annual discount factor	(446,366)	(354,661)	(282,205)
Standardized measure of discounted future cash flows	$ 807,897	$ 647,292	$ 443,118
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 1,062,258	$ 889,940	$ 520,976
Future production costs	(404,891)	(286,197)	(91,675)
Future development costs	(46,312)	(40,023)	(11,551)
Future income tax expense	(166,333)	(96,431)	(72,895)
	444,722	467,289	344,855
10% annual discount factor	(190,655)	(190,822)	(126,436)
Standardized measure of discounted future cash flows	$ 254,067	$ 276,467	$ 218,419

	December 31,		
	2005	2004	2003
		(In thousands)	
AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 718,481	$ 333,091	$ 713,459
Future production costs	(66,151)	(75,381)	(212,615)
Future development costs	(250,705)	(14,497)	(261,413)
Future income tax expense	(140,185)	(81,680)	(17,062)
	261,440	161,533	222,369
10% annual discount factor	(105,271)	(23,520)	(98,141)
Standardized measure of discounted future cash flows	$ 156,169	$ 138,013	$ 124,228
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 41,208,957	$31,344,288	$20,252,414
Future production costs	(11,748,608)	(8,883,850)	(5,978,072)
Future development costs(a)	(3,407,271)	(2,118,766)	(1,598,021)
Future income tax expense	(8,141,823)	(6,012,779)	(3,309,608)
	17,911,255	14,328,893	9,366,713
10% annual discount factor	(10,614,358)	(7,685,818)	(4,783,460)
Standardized measure of discounted future cash flows	$ 7,296,897	$ 6,643,075	$ 4,583,253

(a) Includes $357.5 million, $258.1 million and $208.1 million of undiscounted future asset retirement expenditures estimated as of December 31, 2005, 2004 and 2003, respectively, using current estimates of future abandonment costs. See Notes B and L for corresponding information regarding the Company's discounted asset retirement obligations.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION — (Continued)
Years Ended December 31, 2005, 2004 and 2003

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Oil and gas sales, net of production costs	$(2,227,267)	$(1,719,990)	$(1,136,520)
Net changes in prices and production costs	3,932,683	2,082,706	670,165
Extensions and discoveries	459,251	302,794	413,777
Development costs incurred during the period	446,978	249,890	202,396
Sales of minerals-in-place	(1,492,864)	(14,222)	—
Purchases of minerals-in-place	645,315	2,058,195	198,442
Revisions of estimated future development costs	(907,229)	(447,828)	(444,726)
Revisions of previous quantity estimates	(595,873)	140,950	458,468
Accretion of discount	908,047	644,238	514,608
Changes in production rates, timing and other	78,880	(167,400)	(71,557)
Change in present value of future net revenues	1,247,921	3,129,333	805,053
Net change in present value of future income taxes	(594,099)	(1,069,511)	(348,352)
	653,822	2,059,822	456,701
Balance, beginning of year	6,643,075	4,583,253	4,126,552
Balance, end of year	$ 7,296,897	$ 6,643,075	$ 4,583,253

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2005 and 2004:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
Year ended December 31, 2005:				
Oil and gas revenues, as reported	$520,312	$544,600	$558,382	$622,207
Less discontinued operations	(19,948)	(9,876)	—	—
Total oil and gas revenues, as restated	$500,364	$534,724	$558,382	$622,207
Total revenues, as reported	$550,866	$592,644	$568,236	$691,301
Less discontinued operations	(19,948)	(9,876)	—	—
Total revenues, as restated	$530,918	$582,768	$568,236	$691,301
Total costs and expenses, as reported	$414,346	$387,125	$421,166	$452,851
Less discontinued operations	(11,655)	(6,069)	—	—
Total costs and expenses, as restated	$402,691	$381,056	$421,166	$452,851
Net income	$ 84,657	$185,559	$123,573	$140,779
Net income per share:				
Basic	$ .59	$ 1.32	$ .90	$ 1.11
Diluted	$ .58	$ 1.28	$ .88	$ 1.08
Year ended December 31, 2004:				
Oil and gas revenues, as reported	$435,527	$435,930	$441,724	$519,482
Less discontinued operations	(14,942)	(16,346)	(16,149)	(17,855)
Total oil and gas revenues, as restated	$420,585	$419,584	$425,575	$501,627
Total revenues, as reported	$437,249	$437,308	$443,151	$529,068
Less discontinued operations	(14,942)	(16,346)	(16,149)	(17,855)
Total revenues, as restated	$422,307	$420,962	$427,002	$511,213
Total costs and expenses, as reported	$337,284	$315,847	$338,708	$375,724
Less discontinued operations	(13,526)	(11,472)	(11,673)	(12,501)
Total costs and expenses, as restated	$323,758	$304,375	$327,035	$363,223
Net income	$ 60,188	$ 69,702	$ 80,916	$102,048
Net income per share:				
Basic	$ .51	$ .59	$ .68	$ .71
Diluted	$ .50	$ .58	$ .67	$ .69

During May and August 2005, the Company sold certain Canadian and United States Gulf of Mexico shelf assets, respectively, that qualified as discontinued operations pursuant to SFAS 144. In accordance with SFAS 144, the Company reclassified the results of operations and gains on the sales of the divested assets from continuing operations to discontinued operations in the Company's consolidated statements of operations. See Note V of Notes to Consolidated Financial Statements for additional information regarding these divestitures that gave rise to the adjustments in the tables above.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures. The Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Exchange Act, the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of the Company's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in internal control over financial reporting. There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the Company's last fiscal quarter that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2005, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework", issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting".

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
Pioneer Natural Resources Company:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Pioneer Natural Resources Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2005 and 2004 and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2005 of the Company and our report dated February 15, 2006 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas
February 15, 2006

ITEM 9B. OTHER INFORMATION

In November 2005 the Compensation and Management Development Committee of the Board established 2006 base salaries and bonus targets for the Company's Chief Executive Officer and four most highly compensated executive officers other than its Chief Executive Officer, as described below. Determination of the most highly compensated executive officers is made by reference to total annual salary and bonus for 2005. The 2006 bonus target is shown as a percentage of 2006 base salary, and the actual amount paid may be at, above or below the target level:

Name and Position	2006 Base Salary	2006 Bonus Target
Scott D. Sheffield, Chairman and Chief Executive Officer	$850,000	100%
Timothy L. Dove, President and Chief Operating Officer	$525,000	85%
A.R. Alameddine, Executive Vice President, International Negotiations	$340,000	65%
Chris J. Cheatwood, Executive Vice President — Worldwide Exploration	$340,000	65%
Danny L. Kellum, Executive Vice President — Domestic Operations	$340,000	65%

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2006 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2006 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

See "Item 5. Market for Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities" for information regarding the Company's equity compensation plans. The remaining information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2006 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The remaining information required by Item 404 of Regulation S-K in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2006 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2006 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Listing of Financial Statements

Financial Statements

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

Report of Independent Registered Pubic Accounting Firm

Consolidated Balance Sheets as of December 31, 2005 and 2004

Consolidated Statements of Operations for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003

Notes to Consolidated Financial Statements

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(c) are included in the Company's Form 10-K filed with the SEC on February 17, 2006.

(c) Financial Statement Schedules

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

Shareholder Information

STOCK EXCHANGE LISTING–COMMON STOCK

Ticker symbol: PXD
New York Stock Exchange

CORPORATE HEADQUARTERS

Pioneer Natural Resources Company
5205 N. O'Connor Blvd., Suite 900
Irving, TX 75039
(972) 444-9001

INTERNET ADDRESS

www.pxd.com

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer or exchange of shares, lost certificates or change of address should be directed to:

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
(888) 509-5586
Internet Address: www.continentalstock.com
E-Mail: pioneer@continentalstock.com

ANNUAL MEETING

The Annual Meeting of stockholders will be held Wednesday, May 3, 2006, at 9:00 a.m. CDT at the Marriott Las Colinas Hotel, 223 W. Las Colinas Blvd., Irving, Texas.

INFORMATION REQUESTS

To receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission, to obtain other Pioneer publications or to be placed on the direct mailing list, please contact:

Pioneer Natural Resources Company
Investor Relations
5205 N. O'Connor Blvd., Suite 900
Irving, TX 75039
(972) 969-3583
ir@pxd.com

INVESTOR RELATIONS/MEDIA CONTACTS

Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial condition are encouraged to contact Frank Hopkins, Vice President, Investor Relations at (972) 444-9001. Media inquiries should be directed to Susan Spratlen, Vice President, Corporate Communications and Public Affairs at (972) 444-9001.

OTHER OFFICE LOCATIONS

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Telephone: 44 1483 243517

Pioneer Natural Resources Alaska, Inc.
Kenneth H. Sheffield, Jr., President
700 G Street, Suite 600
Anchorage, AK 99501
Telephone: (907) 277-2700

Pioneer Natural Resources Canada Inc.
Todd A. Dillabough, President
2900, 255-5th Avenue S.W.
Calgary, AB T2P 3G6
Canada
Telephone: (403) 231-3100

Pioneer Natural Resources Nigeria Ltd.
Gregg M. Moser, Managing Director
Address after June 1:
Plot 90 Ajose Adeogun Street - 3rd Floor
Victoria Island, Lagos, Nigeria

Pioneer Natural Resources South Africa (PTY) Ltd.
Marek Ranoszek, General Manager
21st Floor, #1 Thibault Square
1 Long Street,
Cape Town 8001, RSA
Telephone: 27 21 425 5012

Pioneer Natural Resources Tunisia Ltd.
Hashim Alkhersan, Manager
La Residence Lakeo – 3rd Floor
Rue Du Lac Michigan
Les Berges du Lac
1053 – Tunis, Tunisia
Telephone: 216-71-960 885

Board of Directors

Scott D. Sheffield
Chairman and Chief Executive Officer

James R. Baroffio [3,4]
Former President
Chevron Canada Resources

Edison C. Buchanan [3,4]
Former Managing Director
Credit Suisse First Boston

R. Hartwell Gardner [2,4]
Retired Treasurer
Mobil Corporation

Jerry P. Jones [2,4]
(Retiring May 2006)
Retired Shareholder and Of Counsel
Thompson & Knight, P.C.

Linda K. Lawson [2,4]
Former Vice President
Williams Companies

Andrew D. Lundquist [3,4]
Managing Partner
Lundquist, Nethercutt & Griles LLC

Charles E. Ramsey, Jr. [1,3,4]
Financial Consultant

Frank A. Risch [2,4]
Retired Vice President and Treasurer
Exxon Mobil Corporation

Mark S. Sexton [4]
Chief Executive Officer
KFx, Inc

Robert A. Solberg [2,4]
Retired Vice President
Texaco, Inc.

Jim A. Watson [2,4]
Senior Counsel
Carrington, Coleman,
Sloman & Blumenthal L.L.P

Committee Membership

1 LEAD DIRECTOR
2 AUDIT COMMITTEE
3 COMPENSATION AND MANAGEMENT DEVELOPMENT COMMITTEE
4 NOMINATING AND CORPORATE GOVERNANCE COMMITTEE

Officers

Scott D. Sheffield
Chairman and Chief Executive Officer

Timothy L. Dove
President and Chief Operating Officer

A. R. Alameddine
Executive Vice President,
Worldwide Negotiations

Mark S. Berg
Executive Vice President and
General Counsel

Chris J. Cheatwood
Executive Vice President,
Worldwide Exploration

Richard P. Dealy
Executive Vice President and
Chief Financial Officer

William F. Hannes
Executive Vice President,
Worldwide Business Development

Danny L. Kellum
Executive Vice President,
Domestic Operations

Jay P. Still
Executive Vice President,
Western Division

Thomas C. Halbouty
Vice President,
Chief Information Officer

Darin G. Holderness
Vice President and
Chief Accounting Officer

Frank E. Hopkins
Vice President, Investor Relations

Mark H. Kleinman
Corporate Secretary and
Chief Compliance Officer

David McManus
Vice President, International Operations

Larry N. Paulsen
Vice President,
Administration and Risk Management

Susan A. Spratlen
Vice President,
Corporate Communications and
Public Affairs

Roger W. Wallace
Vice President, Government Affairs

PIONEER NATURAL RESOURCES

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